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1990 RELIABILITY ASSESSMENT

THE FUTURE OF BULK ELECTRIC SYSTEM RELIABILITY IN NORTH AMERICA 1990-1999

North American Electric Reliability Council

1990
Reliability Assessment

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Bulk Electric System Reliability
in
North America
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September 1990

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Foreword

About the Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to coordinate, promote, and communicate about the RELIABILITY of their generation and transmission systems. NERC is comprised of nine Regional Reliability Councils and one Affiliate encompassing virtually all of the electric utility systems in the United States, Canada, and the northern portion of Baja California, Mexico.

NERC is governed by a 27-member Board of Trustees. This Board is comprised of two utility executives from each of the nine Regional Reliability Councils, plus others to assure at least one representative from Canada and two from each segment of the industry: investor-owned, federal, rural electric cooperative, and state/municipal electric systems.

Meetings of the Board are attended by observers from the U.S. Department of Energy, the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, the Canadian Electrical Association, the Electric Power Research Institute, and more recently the National Association of Regulatory Utility Commissioners.

NERC's strength lies in its ability to call upon unmatched electric utility managerial and technical expertise and experience from the Regions. Its technical activities are conducted by its Engineering and Operating Committees. The NERC staff provides project coordination and support for the Council's activities.

About This Report

The NERC Board of Trustees created the Reliability Assessment Subcommittee (RAS) in 1970 to annually review the overall reliability of the existing and planned generation and transmission systems of the nine Regional Reliability Councils.

This 1990 Reliability Assessment report presents:

- *An assessment of electric generation and transmission reliability through 1999,*
- *A discussion of the key factors and issues affecting the reliability of future electric supply, and*
- *Detailed regional assessments of electric supply reliability, including reliability issues of specific regional concern.*

In preparing this report, the RAS interviewed representatives of selected Regions and reviewed detailed self-assessments prepared by each Region, including aggregate forecasts of peak demand and planned capacity resources. The RAS appraised regional plans for future electric generation and transmission facilities, and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the RAS members.

For the first time, a reliability assessment of the interconnected electric systems of the Alaska Systems Coordinating Council (ASCC), the NERC Affiliate, is included. These nine interconnected systems, commonly known as the Alaskan Railbelt electric utility systems, account for 75% of the utility net generation in Alaska and serve three major areas: the Fairbanks area, the Anchorage Bowl, and the Kenai Peninsula.

Unless otherwise noted, the data presented reflects conditions as of January 1, 1990. In general, ASCC data is excluded from the figures and tables unless specifically indicated otherwise. Detailed background data, which is the basis for the assessment, is included in a companion NERC report — "1990 Electricity Supply & Demand for 1990-1999."

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ECAR — East Central Area Reliability Coordination Agreement 45

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Executive Summary

Electric utilities have adequate plans for the 1990-1999 period to provide reliable electric service to their customers. However, many issues threaten the implementation of these plans. This report discusses the key issues and risks to future electric system reliability. They include:

Environmental Impacts — The single most significant threat to reliability is the impending amendment of the U.S. Clean Air Act. The final version of this legislation may invalidate many of the conclusions in this report. Proposed regulations related to electric and magnetic fields also have the potential for adversely impacting electric system reliability. It is important that utilities and public policymakers work together to achieve the proper long-term balance among safety, reliability, and economics and their impact on the environment.

Demand Uncertainty — Making accurate electricity demand forecasts is becoming more difficult because of the increasing uncertainty in socioeconomic variables such as conservation and energy legislation. The recent trend of actual demands exceeding forecasts underscores this difficulty. Underestimating the future demand for electricity can lead to supply shortfalls.

Increased Availability of Generators — Reliability in some Regions depends on improving the availability of generators by eliminating or moving scheduled maintenance from peak demand periods and by reducing forced outage rates. If these improvements are not realized, increased dependence on neighboring systems may be necessary.

Transmission Deficiencies — Transmission deficiencies exist in some areas because facilities have not been constructed as planned, or are being used differently than originally intended. The complexities of operating electric systems will continue to increase as a result of these deficiencies. More transactions will compound these complexities unless the transmission systems are properly planned and used.

Fuel Supply Uncertainty — The use of natural gas for generating electricity is expected to increase dramatically. More short lead-time options such as gas-fired combustion turbines and non-utility generators (NUGs) are being planned. Potential environmental constraints on the use of coal will result in less coal-fired economy energy being available and an increase in the use of natural gas. These constraints may also limit emergency support among utilities. Emerging indicators point to significant uncertainties regarding the future availability and deliverability of natural gas.

Unspecified Capacity — Identification of needed capacity resources for only five years into the future has become a common practice. This is due in part to many utilities relying on short lead-time supply options. The risk is that utilities may not be able to implement a specific course of action in time to assure that the additional capacity resources are available when needed.

Disincentives — Regulatory disallowances, inconsistent policies, delays, and uncertainties have created powerful disincentives to adding generation and transmission facilities needed to maintain reliability. These disincentives must be resolved if reliability is to be preserved.

Specific regional reliability concerns identified in this assessment include:

ECAR — Compliance with currently proposed acid rain legislation is expected to have some impact on about 50,000 megawatts (MW) of capacity in ECAR. The uncertainties associated with compliance, including potential impacts on generation availability and the influence of proposed emission caps on inter-utility emergency assistance, are serious concerns.

ERCOT — Delays in the construction of critical 345 kV transmission lines and dependence on natural gas generation are major concerns for continued electric system reliability in this Region.

MAAC — Recent limitations in the interregional transmission systems have rendered MAAC unable to receive desired levels of emergency assistance at time of need from adjacent Regions. Short-term reinforcements are being made to improve the transmission capability. In the longer term, there is concern that the level of available emergency assistance from neighboring Regions may decline, possibly requiring the installation of additional generating capacity within MAAC to maintain adequate reliability.

MAIN — This Region plans to provide adequate generating capacity on a continuing basis. However, probability studies indicate that considering demand forecast error and uncertainties due to weather, MAIN may have to add additional resources as early as 1996. Consequently, MAIN is already investigating the effectiveness of various strategies to assure adequate reliability.

NPCC — Between 1995 and the end of the forecast period, New England estimates that it will require some 2,460 MW of additional resources, either demand management or capacity, beyond those currently planned. Viable contingent and uncommitted resources, capable of being developed in the required time frame, have been identified well in excess of forecasted need. Commitments to the additional resources required will need to be made in a timely manner to maintain adequate capacity margins.

SERC — Planned resources are adequate to supply forecast peak demand and annual energy. However, if peak demand growth continues to exceed forecast, supply deficiencies could quickly develop.

Utilities are counting on a wide variety of both demand management and supply options. On the demand side, utilities assume that electricity use, which generally tracks the economy, can be reduced by conservation, load management, and customer-owned generation. Supply plans rely heavily on the enhanced performance of existing units, additional utility generators, additional non-utility generators, and the purchase of electricity from neighboring utilities. However, like all plans, these options are not without risk. It is up to both utilities and public policymakers to thoroughly understand and manage these risks to preserve reliability.

Reliability And What It Means To The Customer

When electric supply is disrupted, even for a short period of time, the results can produce a wide range of effects from minor inconvenience to economic loss to endangerment of life. Widespread electric system interruptions have been rare occurrences in the United States and Canada. But such reliability is not easily achieved. Reliability must be first planned, designed, and then built into an electric system. The system also must be operated in a reliable and coordinated manner.

A one hundred percent reliable supply of electricity is impossible to achieve at any cost. Unexpected equipment failures and other uncertainties, such as extreme weather conditions, earthquakes, or fuel supply disruptions, can interrupt electrical supply.

Even when supply margins appear adequate, extraordinary events for which systems were not designed can place electric supply in a vulnerable position. Examples include a large amount of unavailable generation at the time of system peak, multiple transmission line outages, or unexpectedly high customer demand. When these extraordinary conditions occur, utilities may be required to resort to emergency operating procedures, including utility-controlled interruptions of customer service, to balance system demand and supply.

A creeping degradation of the reliability of the electric systems must be avoided. A number of proposals that may ultimately change the way electric utilities are structured and operated are being debated by policymakers. Many of these proposals fail to address associated reliability impacts.

Major 1989 Electric Supply Interruptions

In 1989, four acts of nature caused significant supply problems for electric utilities and their customers in several areas of the United States and Canada, demonstrating that nature can and does cause electric supply interruptions. These events also dramatized the vital role of electricity in modern society.

December 21-25, 1989 — A blast of arctic air blanketed eastern Canada and as far south as the U.S. Gulf coast causing record customer electricity demands and crippling some electric generators. Several electric utilities in Texas and Florida were forced to institute rotating customer outages to avoid total system blackout. Ontario Hydro requested its customers to voluntarily reduce electrical demands during a two-week period.

October 17, 1989 — A major earthquake, measuring 7.1 on the Richter scale, rocked San Francisco and surrounding areas, crumbling highways and buildings, igniting fires, causing 64 deaths, and plunging 1.4 million electric customers into total darkness. Within 48 hours electric service was restored to more than 98% of those interrupted.

September 21-22, 1989 — Hurricane Hugo swept across the eastern U.S. seaboard leaving behind a swath of death and destruction in North Carolina and South Carolina, including a tangle of downed electric transmission and distribution lines. Over 1.5 million customers were without electricity after the storm, and electric utilities suffered extensive damage to their distribution and transmission systems. In most cases, the distribution system had to be rebuilt, not repaired. Energy is the common thread throughout the infrastructure in restoring an area after a natural disaster. In the case of Hurricane Hugo, electricity was essential in the restoration efforts to supply energy to water systems, communications, emergency facilities, and fuel supply systems.

March 13, 1989 — An exceptionally intense geomagnetic disturbance — the result of solar flare activity unleashing a large burst of charged particles that interacted with the earth's magnetic field — caused the outage of five James Bay transmission lines, triggering the collapse of the Hydro-Québec electric system in Canada. The disturbance interrupted electric service to 3 million customers in the province of Québec.

Effects of Electric Supply Interruptions

Most electric utility customers have experienced the effects of an electric supply outage. The majority of these interruptions, when they do occur, are confined to localized areas, and are perhaps caused by a severe thunderstorm or a vehicle striking an electric utility pole.

However, widespread interruptions like those noted above can have significant impacts and consequences, including:

- Disruption of home and business activities
- Extensive economic losses,
- Life threatening conditions,
- Severe limitations in lifestyle,
- Physical damage to equipment and facilities, and
- Looting and vandalism.

Widespread electric supply disruptions can literally bring electrified, computer-dependent, highly-automated societies to an abrupt halt. The more advanced society becomes, the greater become the benefits of reliable electric service, and the more adverse the societal and economic impacts of unreliable service.

Reliability Criteria

Reliability must be planned and built into an electric system. The system also must be operated in a reliable manner. Both planning and operations are well-coordinated activities among the interconnected electric systems of NERC.

As the electric systems have grown, various planning policies and criteria have evolved to serve as guides to help maintain electric system reliability. All electric systems of NERC accept the responsibility to observe NERC policies, criteria, and guides, and to contribute to their continued improvement.

Each Regional Reliability Council has the primary responsibility for development of reliability criteria applicable to its Region for use in planning and designing the expansion of its generation and transmission facilities. An April 1988 NERC report, *Overview of Planning Reliability Criteria of the Regional Reliability Councils of NERC*, presents a summary of the planning reliability criteria of the nine Regions. Reliability criteria concerning the operation of these interconnected electric systems are contained in the *NERC Operating Manual*.

Consequences of Inadequate Reliability

As indicated earlier, widespread electric supply interruptions have a dramatic impact on our safety, our economy, and our lifestyle. Fortunately, most disturbances have been infrequent occurrences that were rectified with limited periods of customer service interruption.

In Argentina, however, during 1989, the longer term problems of generating capacity and electrical energy shortages were key reliability issues. Late in 1988, Buenos Aires, a city of 11 million people, began to experience severe electricity shortages due to extended outages at major generating plants, coupled with a harsh drought that reduced water supplies to hydroelectric plants. The loss of electricity limited working hours, lighting, subway operation, and television broadcasts. These electric supply outages or blackouts continued to affect many Argentine citizens for about a year.

If the same electric supply inadequacies and frequency of interruptions existed in any NERC Region, the ramifications would be enormous. Reliable electric supply not only is a basic need to individual customers and businesses, it is crucial to a Region's economic health.

To date, systems within NERC have never experienced an Argentinean type of extended capacity or energy shortage. However, continuing growth of electrical demand in excess of that forecast, or delays in the completion of planned generating units and transmission facilities could adversely affect the reliability of electric supply. Deficiencies in system reliability could take years to alleviate.

Protection Against Electric Supply Interruptions

Electricity cannot be economically stored. It must be produced on demand. That is, the supply must equal, or balance, the demand at all times.

Electric utilities in the United States and Canada operate complex and highly interconnected generation and transmission networks to supply their customers on demand within the constraints of a balanced system. From time to time, however, conditions can occur for which electric systems were not designed. Even when supply margins appear adequate, extraordinary events can place systems in a vulnerable position. Examples include:

- An unusually large amount of unavailable generation,
- Multiple outages of several transmission lines, or
- Unexpectedly high customer demand.

When these conditions occur, and if time permits, utilities will rely on preplanned emergency procedures to attempt to balance demand and supply. These actions are needed to protect against an uncontrolled shutdown or blackout of the entire system which could result in damage to equipment and delay restoration.

Emergency operating procedures generally are implemented after all available electric generating sources have been called upon, and after all contractually interruptible customer demands have been curtailed. These procedures include public appeals to customers to voluntarily reduce their electrical demands, utility-instituted system voltage reductions, and utility-controlled customer load shedding (interruption of electric supply to customers by interrupting distribution or lower-voltage electric circuits). Recently, some systems have had to institute one or more of these actions to balance demand and supply so they could continue to serve the major portion of remaining customers.

Future Electric Supply Reliability

In several instances during 1989, nature brought into focus the value of a reliable supply of electricity. This reliability of electric supply is a delicate balance of technical, environmental, and socioeconomic factors. Undue emphasis on any one of these factors without a balanced consideration of the others will adversely impact reliability.

Although the cost of major electric system disturbances can be extremely high, one hundred percent electric system reliability is impossible to achieve at any cost. On the other hand, system reliability should not be compromised for short-term economic benefits. In the long run, short-sighted approaches could result in severe economic penalties to the customer and even endanger public well-being.

A creeping degradation of the reliability of the electric systems must be avoided. A number of proposals that may ultimately change the way electric utilities are structured and operated are being debated by policymakers. Many of these proposals fail to address associated reliability impacts. Each of the proposals, public policies, or regulatory treatments, before implementation, needs to demonstrate its potential effects on existing and future electric system reliability.

The reliability of electric supply should be a primary, not secondary, consideration along with economics, safety, and environmental impact. Addressing reliability must go beyond lip service and represent a continuing commitment to meet regional planning and operating criteria. Electric utilities and public policymakers share the responsibility to ensure that an adequate level of electric system flexibility and reliability are available to meet future customer electricity demands.

Peak Demand Projections

The 1990-1999 aggregated projections of peak demand for the United States and Canada are higher than those made last year for 1989-1998. A comparison for 1998, the last common year of the two projections, shows that the summer peak demand for the United States is 11,200 megawatts (MW) or about 1.8% higher than last year's projection. Similarly, the 1998/99 winter peak demand for Canada is 2,700 MW or about 2.9% higher than last year's projection.

The uncertainty in the 1990-1999 estimates of annual peak demand growth of 2% for United States and 2.2% for Canada is illustrated by a bandwidth around each of these projections. For the United States, the bandwidth indicates that there is an estimated 80% probability that the summer peak demand will increase at an annual rate between 1.2% and 2.7% over the 1990-1999 period. This corresponds to a U.S. summer peak demand in the range of 580,000 to 708,000 MW in 1999. For Canada, the annual growth is projected to be between 0.8% and 3.5%, with the same probability, corresponding to a winter peak demand in the range of 82,000 to 111,000 MW in 1999/2000.

All Regions are projecting expanded use of demand management programs to reduce system peak demands and thereby defer the need for new generating capacity. Load management and interruptible demands — the direct utility-controlled portions of demand management — are expected to increase in the United States from 13,100 MW in the summer of 1990 to 18,900 MW in 1999. Similarly, these direct utility-controlled programs will increase in Canada from 1,900 MW in the winter of 1990/91 to 2,300 MW in 1999/2000.

1989 Peak Demands

Due to relatively moderate temperatures, the 1989 summer peak demand in the United States was 1.1% lower than the 1988 summer peak demand experienced during the extremely hot 1988 summer. However, the 1989 peak was 0.3% above forecast as shown in Table 1. Peak demands in six of the nine Regions in the U.S. portion of NERC equalled or exceeded their 1989 summer peak demand forecasts.

In Canada, the 1989/90 winter peak demand was 2.7% above last year's peak, but 0.3% below forecast. The WSCC and NPCC areas of Canada did not reach their projected 1989/90 winter peak demands, while the Canadian portion of MAPP exceeded its 1989/90 winter peak forecast by 3.8%.

In those Regions where actual peak demand has exceeded forecast for a number of years, there is a concern regarding the adequacy of future generation and transmission capacity. The issues that affect peak demand uncertainty are addressed in the "Demand Forecast Uncertainty" chapter.

Table 1 — Actual Peak Demands

United States (Summer)	1988 Actual[a] (Thousands of MW)	1989 Actual[a] (Thousands of MW)	Actual Change (%)	1989 Forecast[b] (Thousands of MW)	1989 Actual vs Forecast (%)
ECAR	79.1	75.4	-4.7	75.6	-0.2
ERCOT	40.8	40.4	-1.1	41.2	-1.9
MAAC	43.1	41.6	-3.5	41.6	0.1
MAIN	41.1	39.5	-4.1	38.4	2.7
MAPP	24.9	24.3	-2.3	23.8	2.3
NPCC	45.2	45.0	-0.5	46.8	-3.9
SERC	115.2	117.1	1.6	115.9	1.0
SPP	49.4	49.4	0.2	49.4	0.0
WSCC	90.6	90.7	0.1	89.2	1.6
Total U.S.	**529.5**	**523.4**	**-1.1**	**521.9**	**0.3**
Canada (Winter)	**1988/90**	**1989/90**		**1989/90**	
MAPP	5.5	6.0	9.0	5.8	3.8
NPCC	53.4	54.7	2.4	55.0	-0.6
WSCC	13.7	13.9	1.1	14.0	-1.1
Total Canada	**72.6**	**74.5**	**2.7**	**74.8**	**-0.3**

Note: Figures are rounded. Percentages are based on complete data.
[a]Metered internal peak demands. (Unadjusted for operator-controlled demand reductions, emergency operating procedures, or weather.)
[b]Based on normal weather for each system within the respective Regions and consistent with the April 1989 IE-411 report forms.

PEAK DEMANDS

Forecast peak demands represent total internal peak demands. Internal peak demands have already been reduced to reflect the effects of demand management programs, such as conservation, not under the direct control of utility system operators, but generally include those customer demands under the direct control or management of the utility system operators, such as utility-controlled water heaters and contractually interruptible customers.

The internal peak demand for a system is equal to the sum of the metered (net) power outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. Thus, internal peak demand is the maximum hourly integrated demand of all customer demands plus losses.

1990-1999 Forecast

The electrical peak demand in the United States is projected to grow at 2% per year. The forecast growth rates are average annual rates calculated for the weather-normalized projections from the first year to the last year of the forecast period (rather than over the period from the actual unadjusted metered peak demand of the previous year to the last year of the forecast). The United States is expected to continue to be summer peaking with its summer peak demand expected to exceed the prior winter's peak by about 11% throughout the forecast period.

Canada is projected to be winter peaking throughout the forecast period with its winter peak growing at 2.2% per year over the nine-year forecast period. Canada's winter peak demand is expected to exceed the prior summer's peak demand by about 39% throughout the forecast period.

These peak demand projections and the annual net energy for load projections are summarized in Table 2. The growth rates for annual net energy for load are slightly higher than the growth rates for peak demand in both the United States and Canada.

The 1990-1999 projections of peak demand for the United States and Canada and recent actual peak demands are illustrated in Figures 1 and 2, respectively. These projections already include the effects of demand management programs, such as conservation and time of use rates, which are not under the control of the system operators. Capacity resources are planned to meet the forecast peak demands less load management and interruptible demands shown as the dashed line of Figures 1 and 2.

The actual peak demands have not been adjusted for the effects of emergency operating procedures or weather conditions that occurred at time of peak nor for the amounts of load management and interruptible demand actually used at peak times. The unadjusted actual peak demands in the United States have grown about 2.3% per year since 1980. This past year was the first year since 1982 that the actual peak demand did not exceed the prior year's peak.

NET ENERGY FOR LOAD

The annual net energy for load (NEL) represents the annual electrical energy needed to serve an electric utility's customers. NEL is not just the energy sold to customers, but includes transmission losses. It represents the electrical energy generated by the utility's generating sources plus electrical energy purchases from other electric utilities and non-utility generators, less electrical energy sales to other electric utilities. NEL does not include energy pumping (or charging) requirements for pumped storage (or other energy storage) generating facilities.

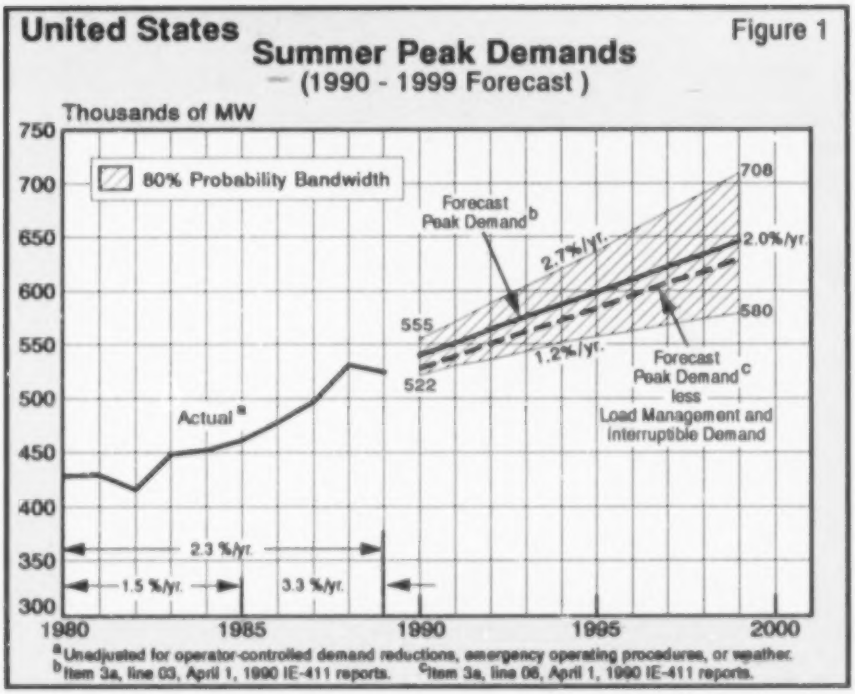
Estimated 80% probability bandwidths for the 1990-1999 forecast peak demands are also shown in Figures 1 and 2. By 1999, the U.S. peak demand in the 80% confidence interval ranges from a high of 708,000 megawatts (MW) to a low of 580,000 MW or about ±10% of the base projection of 646,000 MW. In Canada, the estimated 80% probability bandwidth for the winter peak demand in 1999/2000 ranges from a high of 111,000 MW to a low of 82,000 MW. This is about ±15% of Canada's base winter peak projection for 1999/2000 of 95,700 MW.

The 1990-1999 forecasts of peak demand have increased in eight of the nine Regions compared to 1989's ten-year projections. For example, the 1998 peak demands in these Regions have increased from 1% to 4.4% over the 1998 peak demands projected last year. The SPP peak demands are

Table 2 — 1990-1999 Forecast of Peak Demand and Energy

United States	1990	1999	1990-1999 (%/yr)
Summer Peak Demand[a] (Thousands of MW)	539	646	2.0
Annual Net Energy for Load (Millions of MWh)	2890	3476	2.1
Canada	**1990/91**	**1999/00**	
Winter Peak Demand[a] (Thousands of MW)	79	96	2.2
Annual Net Energy for Load (Millions of MWh)	432	543	2.6

Note: Figures are rounded. Percentages are based on complete data.
[a]Forecast uncertainty is illustrated in Figures 1 (U.S.) and 2 (Canada).

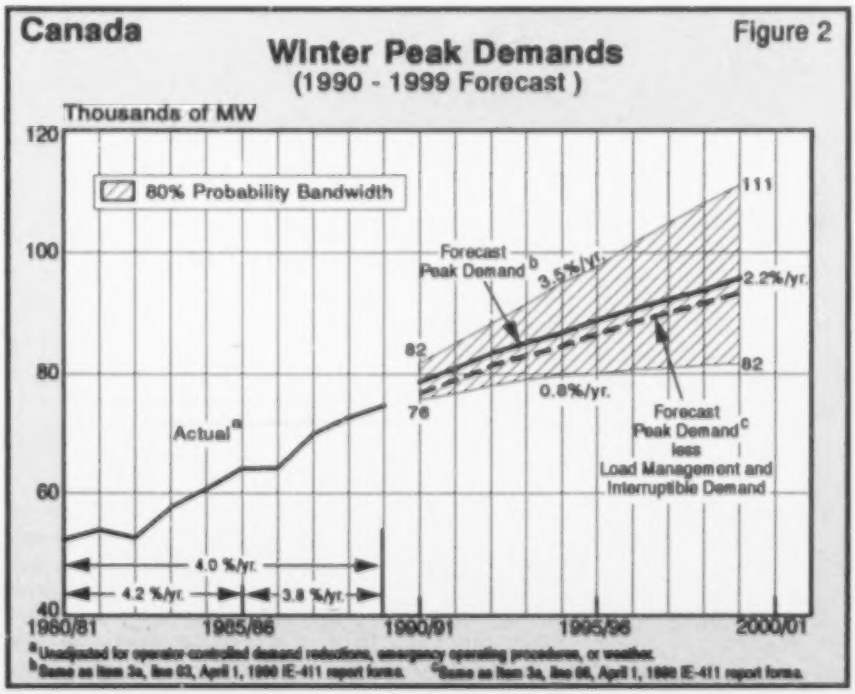


essentially the same as last year's projections. A summary of each Region's peak demand and annual net energy for load projections is presented in the respective regional reliability assessment chapters of this report.

Comparison of Recent Forecasts

The ten-year peak demand forecasts made in 1988, 1989, and 1990 for the United States and Canada are shown in Figures 3 and 4, respectively. After a number of years during the early 1980s in which utilities reduced their peak demand forecasts each year, recent forecasts have increased in absolute terms. However, forecast average annual growth rates show little change.

A comparison of the forecasts for 1997, the last common year of the last three forecasts, indicates that the U.S. summer peak demands have increased by 28,500 MW or 4.8% from the 1988 forecast to the 1990 forecast. Similarly, the 1997/98 winter peak demands for Canada have increased by about 3,700 MW or 4.2% from the 1988 to the 1990 forecast.



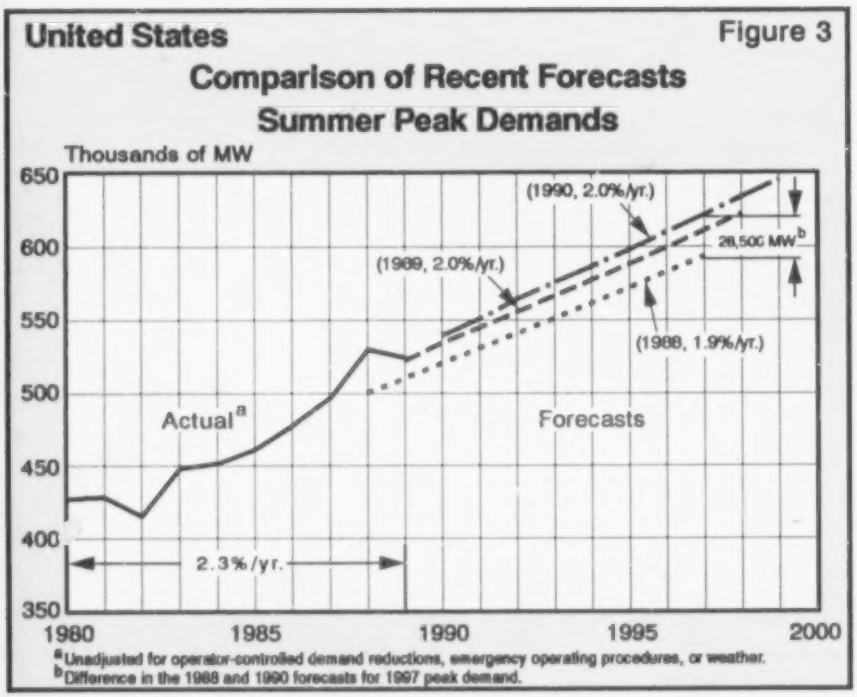
Forecast Uncertainty

The projections of peak demand and annual net energy for load are aggregates of the forecasts, as of January 1990, of the individual utilities comprising the Regional Reliability Councils. These individual utility forecasts are generally "equal probability" forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

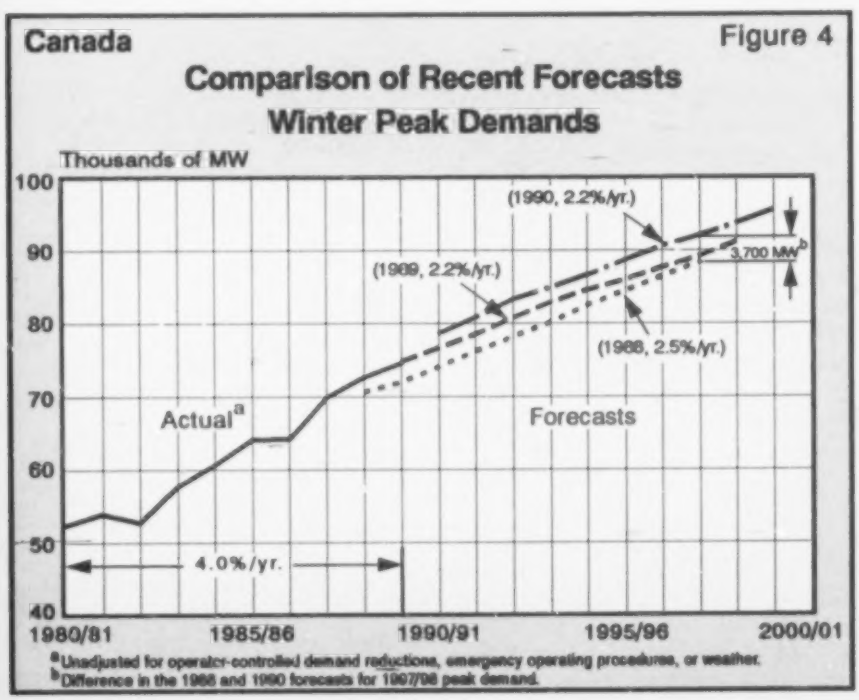
Because electric demand and annual electrical energy requirements are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities, the utilities' forecasts are subject to change. Utilities continually monitor their peak demand and energy requirements and typically update these projections annually.

To avoid implying a degree of certainty not intended in the ten-year forecasts, bands of reasonable variation were developed about the 1990-1999 aggregated peak demand forecasts for the United States and Canada. In developing the U.S. bandwidth, the variables found to relate best to growth in electrical energy were the gross national product, the price of electricity, and the price of natural gas. Relationships between these variables and annual net energy for load were determined. High and low estimates of the variables were then selected to develop high and low annual energy projections about the base or equal probability annual energy projection.

The high and low bounds of the summer peak demand bandwidth of Figure 1 were estimated by a statistical sampling



of the historical relationship between peak demand and net energy for load. The resulting bandwidth range of peak demand annual growth rates for the United States is 1.2% to 2.7%. This bandwidth has been defined such that there is an estimated 80% probability that the future U.S. summer peak demands will fall within the high and low bounds of the bandwidth. This means there is a 10% chance that future U.S. summer peak demands in any year will exceed the upper bound of the bandwidth. Similarly, there is a 10% chance that future demands will be less than the lower bound of the bandwidth.



The variables used in developing the winter peak demand bandwidth of Figure 2 for Canada are the domestic national product, the price of electricity, heating degree days, a weighted average of the price of natural gas and oil, and the effect of utility marketing efforts in the industrial sector. The resulting range of average annual winter peak demand growth rates in Canada is 0.8% to 3.5%. The Canadian and U.S. forecast bandwidth calculation methodologies are similar except for the variables.

It would be incorrect and misleading to apply the absolute value or percentage range of the forecast bandwidths to the forecasts of individual Regional Reliability Councils, individual utilities, or groups of utilities since the bands shown represent a composite of all member utilities in each country.

Demand Management

Demand management programs, which include conservation, load management, and other programs as described in the sidebar, provide utilities with the ability to reduce peak demand and to possibly delay the need for some future generating capacity. However, demand management is not an unlimited resource and may only provide limited demand reduction assistance. It may also reduce the rate of growth in peak demand and thereby delay when a given peak demand may occur, but it will not eliminate growth.

Some utilities have been heavily involved in demand reduction programs for many years, while others are just initiating programs now to gain experience, provide flexibility, and reduce capacity requirements in the future. Utilities in SERC, NPCC, MAIN, and MAAC will be heavily dependent on the success of these programs in satisfying their generating capacity margin requirements over the next ten years.

Load Management and Interruptible Demands

Load management and interruptible demands are those portions of demand management under the direct control of

Table 3
Load Management and Interruptible Demands (1990-1999 Forecast)

Region	1990 Summer Thousands of MW	1990 Summer % Peak Demand	1999 Summer Thousands of MW	1999 Summer % Peak Demand
ECAR	1.0	1.2	1.0	1.1
ERCOT	1.6	3.8	1.7	3.2
MAAC	1.2	2.8	2.2	4.4
MAIN	0.9	2.3	1.2	2.6
MAPP	0.2	0.8	0.4	1.0
NPCC[a]	2.5	2.4	4.2	3.4
SERC	3.4	2.8	5.2	3.4
SPP	0.4	0.8	0.8	1.3
WSCC	3.6	3.5	3.6	2.9
United States	**13.1**	**2.4**	**18.9**	**2.9**
Canada[a]	**1.9**	**2.4**	**2.3**	**2.4**

[a]Winter 1990/1991 and 1999/2000.

utility system operators or interruptible by the customer at the utility's request. The amount of these programs is generally included in (not subtracted from) the peak demand projections for the United States and Canada.

The 1990 and 1999 projections for load management and interruptible demands are summarized in Table 3. The associated peak demand reductions projected to be available from these programs are illustrated in Figures 1 and 2 for the United States and Canada, respectively. It is this reduced demand against which capacity resources were evaluated in the "Generation Reliability Assessment" chapter.

ACTUAL VERSUS FORECAST PEAK DEMANDS

Actual peak demands have not been adjusted for variations from normal weather conditions, demand reductions due to load management and interruptible demand actions, or emergency operating procedures that were in effect during the peak hour.

Forecast peak demands are based on the expectation of normal weather conditions, and are not generally reduced to account for direct utility-controlled demand reductions or emergency operating procedures that could be used if required.

Conclusions made from a comparison between actual and forecast peak demands must be made with caution. Adjustments to one or both quantities may be necessary to assure consistent treatment of operator-controlled load management, interruptible demands, emergency operating procedures, and weather.

The process of adjusting actual peak demand to the peak demand that would have been expected if weather conditions were "normal" is called weather-correcting or weather normalization. This is a complex calculation that can result in a lower weather-corrected actual peak demand if weather conditions during the peak were warmer than normal or in a higher weather-corrected actual peak demand if conditions were cooler than normal for summer peaking systems. The opposite effects occur for winter peaking systems.

DEMAND MANAGEMENT

In this report, "demand management" is the umbrella term used to include all activities undertaken by an electric utility or its customers to influence the amount and timing of electricity use. It includes conservation programs, improvements in the efficiency of both primary energy and electricity use, utility control of certain customer loads, economic incentives embodied in rate design, contractually interruptible customers, and many other similar activities.

LOAD MANAGEMENT

In this report, "load management" includes only that portion of demand management concerned with customer demands under the direct control of the electric utility system operator or interruptible by the customer at the utility's request in accordance with contractual arrangements. The direct switching of water heaters, air conditioners, and irrigation pumps are examples of customer demands that are controlled by utilities. Reductions in customer demand using load management are generally achieved within minutes but may take as long as a few hours.

There is uncertainty as to how much peak demand reduction will be realized at the particular time when load management is needed and implemented. Another concern is that customers, who initially participate in load management programs because of the financial incentives, may decide, once the electric supply to their equipment has actually been interrupted a number of times, that the inconvenience of the interruptions outweighs the cost savings and withdraw from the programs. More experience will be required to establish the long-term availability, effectiveness, and customer acceptance of these programs.

Generating Capacity Projections

Planned capacity additions over the 1990-1999 period total 86,200 MW in the United States and 22,000 MW in Canada. Of these planned capacity additions, about 3,000 MW of longer lead-time utility units scheduled for service by 1994, and about 2,900 MW of short lead-time units scheduled for service by 1992 are as yet not under construction. It is unlikely that all of this new capacity will be completed as scheduled.

NUGs are projected to account for 20,000 MW or about 18% of the planned capacity additions in NERC over the next ten years, primarily in the United States. By 1999, NUG capacity will equal about 34,800 MW or 4% of the total summer capacity resources in NERC.

1989 Generating Capacity

The total installed generating capacity, as shown in Table 4, increased in NERC by 8,145 MW (1.1%) in 1989 over 1988. This increase was 0.2% greater than forecast.

1990-1999 Projections

New unit capacity additions of 108,900 MW are planned in NERC over the 1990-1999 period. A summary of generating unit additions, changes, and retirements is shown in Table 5.

Table 4 — Installed Generating Capacity — MW

	1988 Actual	1989 Actual	Change (%)	1989 Forecast	Actual vs. Forecast (%)
United States[a]	661,580	673,316	1.8	667,710	0.8
Canada[b]	83,229	84,691	1.8	85,802	-1.3
NERC-Total[a,c]	745,706	753,851	1.1	752,540	0.2

[a]Summer [b]Winter
[c]Includes capacity located in that part of Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Table 5 — Generating Unit Additions, Changes, and Retirements (1990-1999 Forecast)

	United States		Canada		NERC-Total	
Type	Thousands of MW	% of Total	Thousands of MW	% of Total	Thousands of MW	% of Total
Nuclear	9.3[a]	10.8	3.5	16.0	12.8[a]	11.8
Coal	13.4	15.6	3.0	13.8	16.4	15.1
Hydro	1.3	1.5	10.9	49.3	12.2	11.2
Oil/Gas	28.9	33.5	1.8	8.1	31.3[b]	28.7
Pumped Storage	2.4	2.7	0.0	0.0	2.4	2.2
Other (Utility)[c]	12.6	14.7	1.1	5.0	13.8[b]	12.7
NUGs	18.3	21.2	1.7	7.8	20.0	18.3
Additions	**86.2**	**100.0**	**22.0**	**100.0**	**108.9[b]**	**100.0**
Changes[d]	**11.4**	—	**0.6**	—	**12.0**	—
Retirements	**3.9**	—	**0.3**	—	**4.2**	—
Net Total	**93.7**	—	**22.3**	—	**116.7[b]**	—

Note: Figures are rounded. Percentages are based on complete data.
[a]Perry 2 and Washington Nuclear Project units, WNP 1 and 3, are not included.
[b]Includes 600 MW of oil-fired and 75 MW of geothermal additions in WSCC-Mexico.
[c]Includes utility capacity fueled by geothermal, wind, solar, wood, refuse, and similar energy sources and capacity of unspecified fuel type.
[d]Includes unit rerates, shutdowns, and reactivations from shutdown status.

Utility-owned coal and nuclear generating units account for 26.4% of the U.S. generating capacity additions over the next ten years, and oil- and gas-fired units 33.5%. Non-utility generators (NUGs) comprise a significant portion of the U.S. additions at 21.2%. In Canada, nuclear, hydro, and coal-fired generating units comprise 79.1% of the planned capacity additions. Of the 33,800 MW included in the other (utility) and NUG categories in the United States and Canada, about 17,740 MW are indicated as unspecified or unknown as to fuel type.

Generating Unit Construction Status

The relatively few remaining nuclear units planned for service over the next ten years are well along in construction with all but one being more than 50% complete.

Of the planned coal-fired units, 49% in the United States and 60% in Canada are in some phase of construction. This and similar data are shown for utility and non-utility planned capacity additions in

Table 6 — Construction Status of Generating Unit Additions (1990-1999)

	United States			Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Nuclear[a]						
Not Yet Under Construction[b]	0	0.0	0.0	0	0	0.0
Under Construction (<50%)	0	0.0	0.0	1	0.9	25.0
Under Construction (>50%)	8	9.3	100.0	3	2.6	75.0
Total Nuclear	**8**	**9.3**	**100.0**	**4**	**3.5**	**100.0**
Coal						
Not Yet Under Construction[b]	25	6.9	51.5	5	1.2	39.9
Under Construction (<50%)	6	3.1	22.9	3	0.7	24.9
Under Construction (>50%)	6	3.4	25.6	3	1.1	35.2
Total Coal	**37**	**13.4**	**100.0**	**11**	**3.0**	**100.0**
Hydro[c]						
Not Yet Under Construction[b]	50	0.8	64.3	14	4.8	43.9
Under Construction (<50%)	6	0.2	16.2	13	3.7	33.8
Under Construction (>50%)	7	0.3	19.5	8	2.4	22.3
Total Hydro	**63**	**1.3**	**100.0**	**35**	**10.9**	**100.0**
Oil/Gas						
Not Yet Under Construction[b]	231	26.9	93.0	12	1.8	100.0
Under Construction (<50%)	18	1.5	5.1	0	0.0	0.0
Under Construction (>50%)	9	0.5	1.9	0	0.0	0.0
Total Oil/Gas	**258**	**28.9**	**100.0**	**12**	**1.8**	**100.0**
Other (Utility)[d]						
Not Yet Under Construction[b]	66	12.6	83.6	5	1.1	100.0
Under Construction (<50%)	15	2.3	15.9	0	0.0	0.0
Under Construction (>50%)	3	0.1	0.5	0	0.0	0.0
Total Other (Utility)	**84**	**15.0**	**100.0**	**5**	**1.1**	**100.0**
Non-Utility Generators (NUGs)[e]						
Not Yet Under Construction[e]	—	15.9	87.0	—	1.5	87.9
Under Construction (<50%)	—	1.3	6.9	—	0.0	0.0
Under Construction (>50%)	—	1.1	6.1	—	0.2	12.1
Total NUGs	— [e]	**18.3**	**100.0**	— [e]	**1.7**	**100.0**
Total (All Units)[e]						
Not Yet Under Construction[e]	—	63.1	73.2	—	10.4	47.1
Under Construction (<50%)	—	8.4	9.8	—	5.3	24.1
Under Construction (>50%)	—	14.7	17.0	—	6.3	28.8
Total (All Units)	— [e]	**86.2**	**100.0**	— [e]	**22.0**	**100.0**

Note: Figures are rounded. Percentages are based on complete data.

[a] Perry 2 and Washington Nuclear Project units, WNP 1 and 3, are in some stage of construction but are not included.

[b] Includes utility units planned but not utility authorized, units with regulatory approval pending, and units with regulatory approval received but not yet under construction.

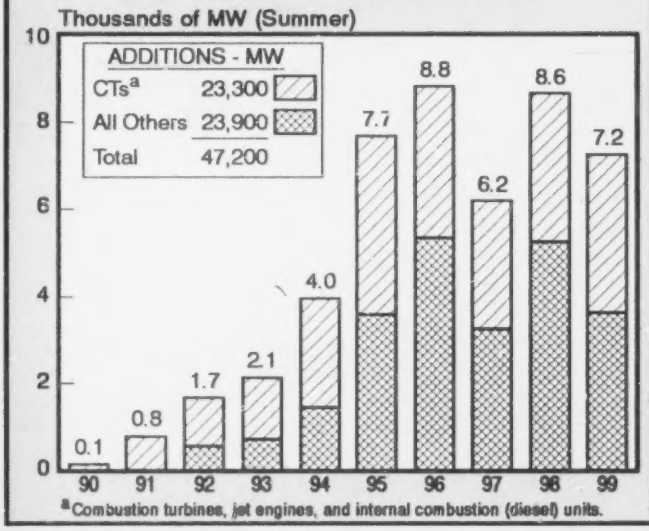
[c] Does not include pumped storage.

[d] Includes utility capacity fueled by geothermal, wind, solar, wood, refuse, and similar energy sources and capacity of unspecified fuel type.

[e] NUG additions are not available by unit. Further, most NUG units are not reported to be under construction.

United States Figure 5

Utility Generator Unit Additions Not Yet Under Construction



Canada Figure 6

Utility Generator Unit Additions Not Yet Under Construction

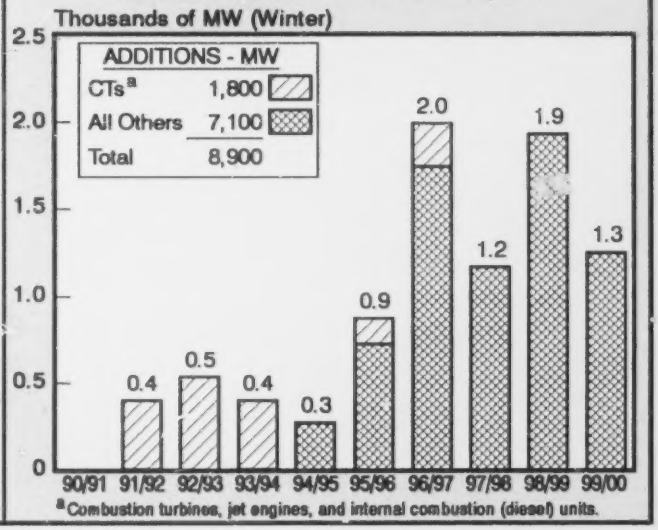


Table 6. A substantial portion of the additions in the hydro and other (utility) categories is not yet under construction. In addition, 87% of the capacity in the NUG category is not reported to be under construction.

About 56,100 MW or 52% of the total planned additions in the United States and Canada consist of utility units that are not yet under construction. Of this amount, about 25,100 MW consist of combustion turbines, jet engines, and internal combustion (diesel) units, all of which are generally short lead-time generator additions. The remaining 31,000 MW include longer lead-time types of capacity as well as about 12,300 MW of capacity of unspecified type. Figures 5 and 6 indicate that about 3,000 MW of the longer lead-time capacity, primarily in the United States, have projected in-service dates of 1994 or earlier, and about 2,900 MW of the short lead-time capacity not yet under construction have projected in-service dates of 1992 or earlier. In addition, about 15,100 MW of NUG capacity of various sizes, scheduled for service by 1994, are not reported to be under construction. Recognizing the typical lead-time requirements, it is unlikely that all of this 21,000 MW of new capacity not yet under construction will be completed on schedule.

Non-Utility Generators

All nine Regional Reliability Councils have some level of NUG activity. By the summer of 1999, NUGs are projected to total 34,800 MW or about 4% of the 1999 total planned capacity resources of NERC. A breakdown of this capacity is shown in Table 7.

There has been a significant increase in reliance on NUGs for future capacity over the last few years. For example, the projected 1998 NUG installed capacity has increased 5,240 MW over last year's projection, an increase of 17.6%.

Comparison of Recent Projections

A comparison of last year's and this year's forecast of generating capacity for the summer of 1998 in the United States and the winter of 1998/99 in Canada, respectively, is shown in Tables 8 and 9.

The U.S. total projected summer generating capacity in 1998 is about 19,900 MW higher than last year's forecast. This consists primarily of an 8,100 MW increase in oil- and gas-fired units, 4,600 MW of NUGs, and 4,100 MW of other (utility) units. On the other hand, the total projected winter capacity for Canada in 1998/99 is approximately the same as the previous forecast.

Table 7 — Existing and Planned Non-Utility Generators (NUGs) by Summer 1999

Region	Total Projections MW	% of Total Capacity Resources
ECAR	2,501	2.4
ERCOT	824	1.4
MAAC	4,746	7.9
MAIN	187	0.4
MAPP	436	1.1
NPCC	9,002	6.2
SERC	5,951	3.4
SPP	601	0.8
WSCC	10,529	6.6
NERC-Total	**34,777**	**4.0**
United States	**33,009**	**4.3**
Canada	**1,768**	**1.7**

Table 8 — Projected Generating Capacity Comparison of Forecasts for the United States (1998 Summer)

Projected Generating Capacity	This Year's Forecast (Thousands of MW)	% of Total	Last Year's Forecast (Thousands of MW)	% of Total	Change in Forecast (Thousands of MW)
Nuclear	104.4	13.9	106.1	14.5	-1.7
Coal	306.3	40.7	303.5	41.4	2.8
Hydro	68.6	9.1	66.8	9.1	1.8
Oil/Gas	211.5	28.1	203.4	27.8	8.1
Pumped Storage	18.9	2.5	18.7	2.5	0.2
Other (Utility)	9.7	1.3	5.6	0.8	4.1
NUGs	33.4	4.4	28.8	3.9	4.6
Total	**752.8**	**100.0**	**732.9**	**100.0**	**19.9**

Note: Figures are rounded. Percentages are based on complete data.

Planned Capacity Resources Uncertainty

All future plans are subject to uncertainty, and plans for generation capacity are no exception. New utility units are subject to delays due to licensing, regulation, and public intervention, as well as to the complexities of construction of large projects. Non-utility generation plans are also subject to change due to the economic climate and, in some cases, regulatory and tax treatment. In addition, changing requirements for associated cogenerator processes, such as loss of customer steam requirements, could affect the continued operation of some NUG capacity.

The continued operation of existing utility generating capacity as that capacity ages is also subject to uncertainty. By the end of the assessment period, about 16.5% of the U.S. coal-fired capacity (6% in Canada) will be over 40 years old. The extent to which older capacity will continue to be available for service is dependent upon the economic viability of operation, the success of generating unit availability improvement efforts under way at many utilities, and the resultant effects that environmental legislation and regulations may have on that capacity. This includes the U.S. Environmental Protection Agency's application of New Source Performance Standards to maintenance projects as in the case of Wisconsin Electric Power Company in MAIN. Additional information on this example can be found in the MAIN regional chapter.

Table 9 — Projected Generating Capacity Comparison of Forecasts for Canada (1998/99 Winter)

Projected Generating Capacity	This Year's Forecast (Thousands of MW)	% of Total	Last Year's Forecast (Thousands of MW)	% of Total	Change in Forecast (Thousands of MW)
Nuclear	15.5	14.5	15.5	14.8	0.0
Coal	21.2	20.0	22.2	21.3	-1.0
Hydro	56.6	53.1	56.1	53.7	0.5
Oil/Gas	10.8	10.1	9.3	8.9	1.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Other (Utility)	0.8	0.8	0.3	0.3	0.5
NUGs	1.6	1.5	1.0	1.0	0.6
Total	**106.5**	**100.0**	**104.4**	**100.0**	**2.1**

Note: Figures are rounded. Percentages are based on complete data.

NON-UTILITY GENERATORS

A reference document, *Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems*, is available from the North American Electric Reliability Council.

This document defines non-utility generators as facilities for generating electricity that are not owned exclusively by an electric utility and which operate connected to an electric utility system. Included are qualifying cogeneration and small power production facilities under the Public Utility Regulatory Policies Act (PURPA) of 1978, pre-PURPA non-utility owned generators, customer-owned generators not covered by PURPA, and industrial or other independent power producers that operate connected to an electric utility system.

In this *1990 Reliability Assessment* report, the data on non-utility generators (NUGs) is limited to only those NUGs that sell or are projected to sell electric energy or capacity, or both, to electric utilities. Data on industrial or other independently-owned generators that generate electricity for their own consumption are generally excluded from this report.

Utility units covered by sale-leaseback arrangements are not considered as NUGs based on the premise that most will be utility operated and will revert to the utility upon termination of the lease.

Range of Uncertainty

The range of uncertainty of realizing the planned capacity resources is illustrated in Figures 7 and 8 for the United States and Canada, respectively. The heavy upper line represents the total planned capacity resources. The lower bound of the range of uncertainty reflects the results of scenarios postulated to assess the effects of delays of new capacity additions as well as the loss of existing capacity due to pending environmental legislation.

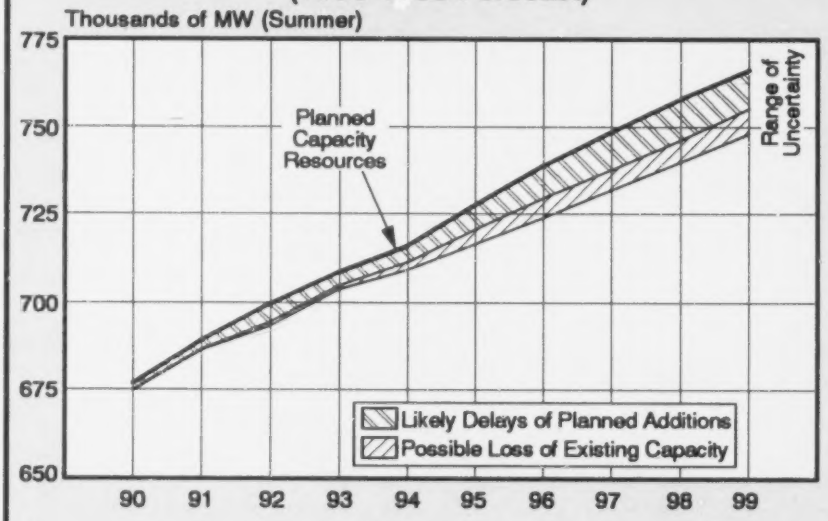
To quantify the uncertainties that exist concerning new capacity additions, a NERC survey was conducted in 1988 regarding the likelihood of delays to the scheduled in-service dates of new generator additions. Subsequent experience has tended to verify the survey projections. Based on the results of this survey, the effects of delays of planned capacity additions, both utility and non-utility, could reduce 1999 planned capacity resources by about 10,700 MW in the United States and by 2,400 MW in Canada.

The possible loss of existing capacity, primarily as a result of likely changes in the Clean Air Act in the United States, was estimated in early 1990. By 1999, about 4,000 MW of coal-fired capability could be lost from service in the United States as a consequence of such legislation through deratings, increased electric requirements for emissions control systems, and anticipated poorer availability of some units retrofitted with emissions controls. Another 3,500 MW may be lost due to premature retirements as a consequence of the Clean Air Act.

In contrast to the situation expected in the United States, less than 500 MW of existing coal-fired capacity is expected to be lost in Canada due to further acid gas regulations. This smaller reduction is primarily due to the much lower percentage of coal-fired capacity in Canada and the much younger age of the units as well as the current wide use of low sulfur coals. There is also a possible loss of existing capacity, about 1,500 MW by 1999, primarily as a result of aging, in terms of technological obsolescence or loss of economic viability of continued operation.

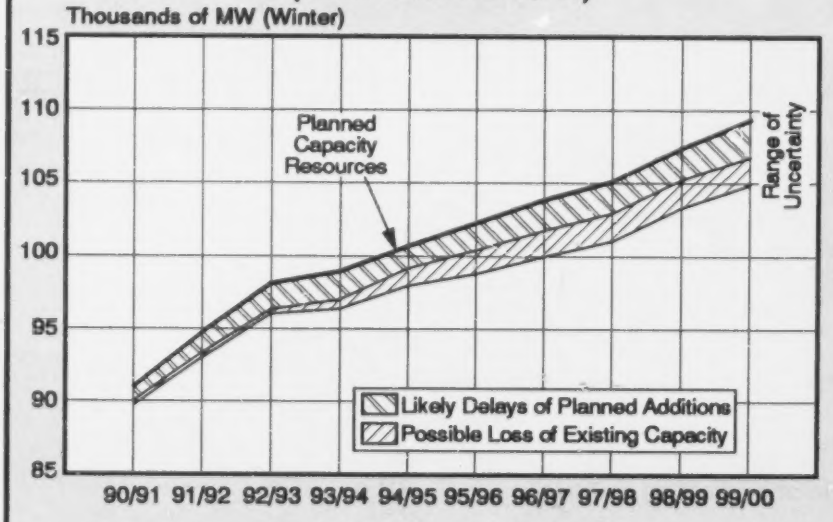
United States Figure 7

Uncertainty of Planned Capacity Resources
(1990-1999 Forecast)



Canada Figure 8

Uncertainty of Planned Capacity Resources
(1990-1999 Forecast)



By the end of the forecast period, delays of new capacity and possible reductions in existing capacity could reduce resources by 18,200 MW and result in 1999 capacity resources in the United States of about 747,600 MW. Similarly, such effects in Canada could reduce resources by 4,400 MW and result in 1999/2000 capacity resources of about 104,900 MW.

Generation Reliability Assessment

All nine Regions are projecting adequate capacity resources to meet the forecast demand requirements throughout the 1990-1999 assessment period, but all Regions have identified a number of risks to maintaining that adequacy. Those Regions most likely to need to rely on capacity resources beyond those currently planned, some beginning as early as 1995, include ECAR, MAAC, MAIN, NPCC, and SERC.

Possible delays of new generating capacity and the loss of existing capacity due primarily to pending clean air legislation could cause capacity shortfalls in the combined Eastern and Québec Interconnections by 1999 if the demand is slightly above forecast. Demand growth approaching the upper bound of the forecast peak demand bandwidth could cause capacity deficiencies in all Interconnections before the end of the assessment period, beginning as early as summer 1992 in the combined Eastern and Québec Interconnections.

Generation Capacity Requirements

Planning sufficient generating capacity to serve customer peak demands involves including allowances for unit scheduled maintenance outages, forced outages, deratings and partial outages, minute-to-minute customer demand variations, demand forecast uncertainty, weather effects, spinning reserve, and other operating considerations. The amount of generating capacity margin required in a given utility or Region is unique. This is due to variations in the physical characteristics of the area, customer demand requirements, system characteristics such as age, size, type, and performance of equipment, and interchange agreements with neighboring systems.

In this report, only a few select factors are addressed — projected peak demands, demand forecast uncertainty, allowance for unexpected generating unit outages, and experience of generating unit availability at the time of peak demand. Additional capacity to meet the other uncertainties will undoubtedly be required and must be addressed by the Regions and individual systems.

Capacity Resources Adequacy

To assess the adequacy of capacity resources to meet the projected peak demand requirements, an estimate of the resources likely to be available at the time of peak demand was derived from the planned capacity resources.

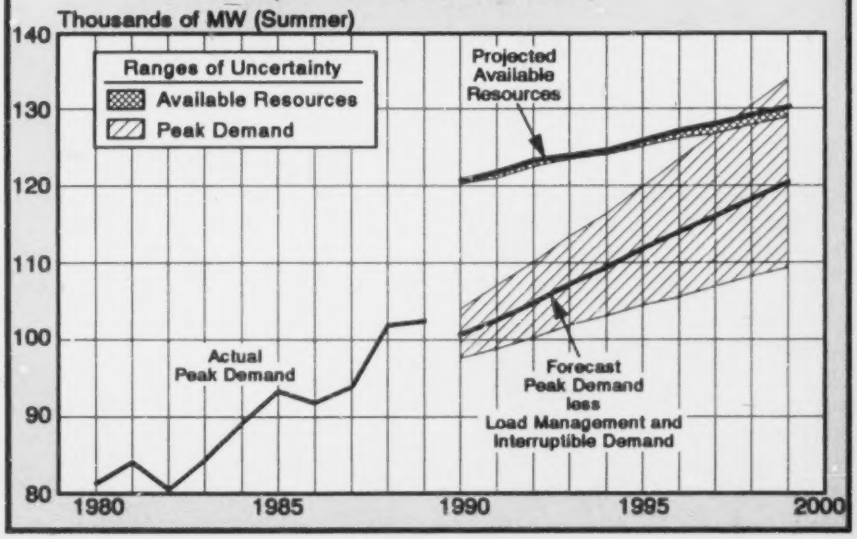
Not all installed generating capacity is available at any given time due to full or partial unit forced outages, seasonal deratings, and maintenance requirements. The amount of this reduction is reported annually by each Region and subregion. Therefore, planned capacity resources throughout the assessment period have been reduced to reflect typical unavailability of generating capacity at time of peak demand. This provides an estimate of the capacity that can be expected to be available to supply the peak demand if the planned capacity resources are placed in service on schedule.

This estimate of expected available capacity was further reduced by an appropriate amount of spinning reserve capacity required to accommodate sudden generating unit outages. The resultant value has been identified as "Projected Available Resources."

As discussed in the "Generating Capacity Projections" chapter, the planned capacity resources have a range of uncertainty because of the likelihood of delays in scheduled new capacity as well as the potential effects of evolving environmental legislation. Accordingly, that range of uncertainty is reflected as a bandwidth of projected available resources.

Western Interconnection Figure 9

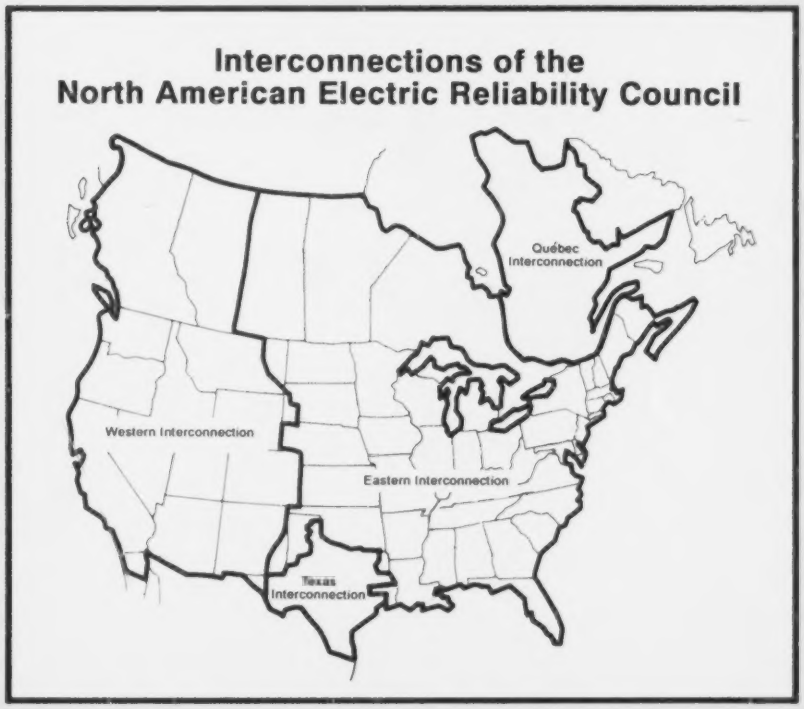
Ranges of Uncertainty for Peak Demand and Projected Available Resources (1990 - 1999 Forecast)



INTERCONNECTIONS

In the one hundred-year history of the electric utility industry, utilities have grown from isolated systems supplying their customers from local generating sources to highly interconnected systems (or "Interconnections") of generating stations and high voltage transmission lines encompassing large geographic areas and many individual utilities. Today, in NERC, there are four major interconnected areas: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and the Québec Interconnection.

Within each Interconnection, individual utility systems are operated in synchronism with each other. This means that all the interconnected utility systems are connected by alternating current (ac) transmission lines and the frequency of the alternating current is the same at all points in the interconnected area. A simple indication of synchronous operation is that all electric clocks in an Interconnection will run at the same speed.



There are other important electrical characteristics of interconnected systems. Changes in demand or generation at any point in the Interconnection will be perceived throughout the Interconnection to varying degrees. Within limits of the transmission systems, demand at any point in the Interconnection can be supplied by generation located at any other point. Transfer of electricity from one point to another will, to some extent, flow over all ac transmission lines in the Interconnection, not just those in the direct path of the transfer.

Because of technical and economic reasons, it is impractical to use alternating current transmission lines to tie the major Interconnections to each other. However, direct current facilities are used for this purpose. The ability to transfer electricity between the Interconnections is limited to the capacity of these dc tie lines, the ability to deliver electricity through the network to the tie points, and by the amount of generating capacity available at the time of the transfer.

In Figures 9, 10, and 11, the range of projected available resources is compared with peak demand projections (less load management and interruptible demands) and the associated peak demand uncertainty bandwidth as described in the "Peak Demand Projections" chapter.

The forecast peak demand is an equal probability forecast. That is, there is a 50% chance of actual demand being either higher or lower than forecast. However, the upper bound of the forecast peak demand bandwidth represents demand values that there is only a 10% chance of exceeding. Where the ranges of uncertainty of projected available resources and peak demand overlap, the adequacy of capacity resources as presently planned is at risk depending upon these uncertainties.

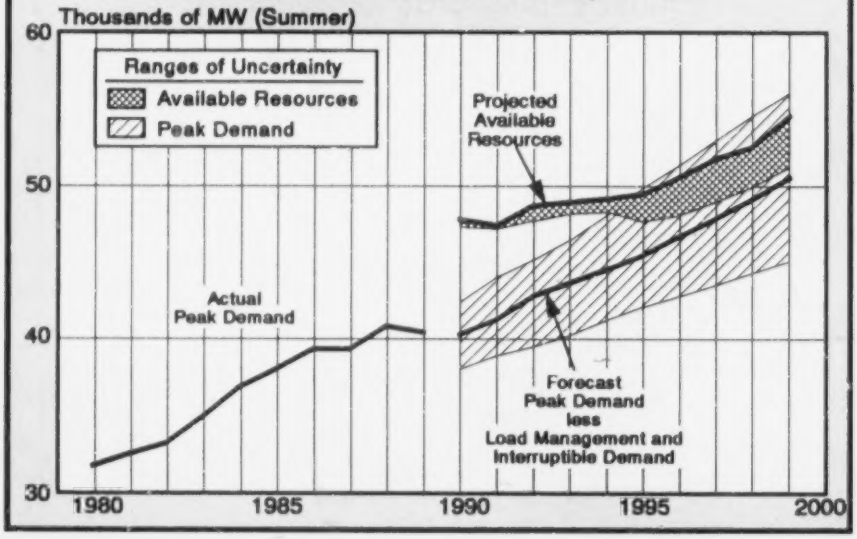
The benefits of load management programs and the use of interruptible demands to reduce capacity requirements have already been taken into account in the peak demands shown on Figures 9, 10, and 11. Weather effects are also reflected in the forecast peak demands on a statistical basis averaged over time. However, weather extremes could cause demand to exceed available capacity even though adequate capacity would be available for the more likely weather conditions.

Interconnection Analysis

There are limits to the degree that available capacity in any area can supply peak demand requirements in any remotely located area. This is particularly the case if more than one Interconnection is involved. Transfer capabilities between the Eastern, Western, and Texas Interconnections are very limited. This is true to a lesser extent between the Eastern and Québec Interconnections. Within an Interconnection, there is generally a greater capability of transferring electricity among the interconnected systems although limitations do exist. Accordingly, an analysis of the adequacy of projected available resources was

Texas Interconnection Figure 10

Ranges of Uncertainty for Peak Demand and Projected Available Resources (1990 – 1999 Forecast)

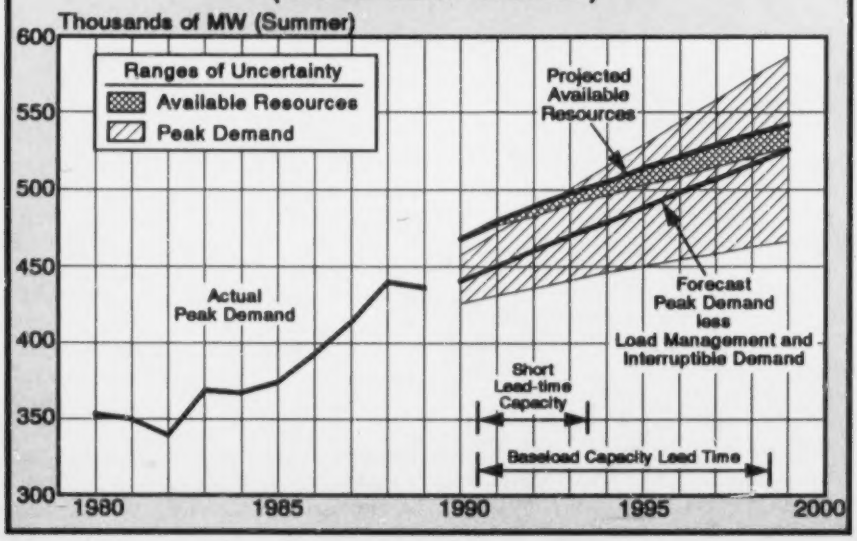


made for each of the four Interconnections of NERC for both the summer and winter seasons.

Two basic simplifications were made in these Interconnection analyses. First, peak demand diversity among the Regions within an Interconnection was not considered. Secondly, all regional generating capacity unavailability at the time of system peak demand was considered to be simultaneous, thereby not taking the diversity of unit outage experience into account.

Eastern/Québec Interconnection Figure 11

Ranges of Uncertainty for Peak Demand and Projected Available Resources (1990 – 1999 Forecast)



In the Western Interconnection and the Texas Interconnection, as shown in Figures 9 and 10, respectively, the range of projected available resources is above the base forecast peak demand (less load management and interruptible demand) throughout the ten-year period. In the worst case, the resources range does not intersect the upper bound of the forecast peak demand until 1995. In contrast, the combined Eastern and Québec Interconnections show a likelihood of capacity shortfall in the summer season, as early as 1992, if the combination of the lower bound of the projected available resources range and the upper bound of the forecast bandwidth should occur, as demonstrated in Figure 11. The likelihood of this occurring is approximately 10%.

The planning of generating capacity is a dynamic activity. Supply plans are modified as demand forecasts change. Therefore, the occurrence of actual peak demands near the upper bound of the demand forecast bandwidth without a change in planned capacity resources is not likely. However, recognition of a significant change in growth rate must occur soon enough to permit ameliorative actions, whether they consist of demand management activities or the addition of generating capacity. The lead-time requirements for both short lead-time and baseload capacity additions are also shown on Figure 11.

The combined Eastern and Québec Interconnections are comprised of seven Regions, each unique in its capacity-demand relationships. The information in Figure 11 is an aggregate of those Regions. It is recognized that available capacity in one Region may not be fully available to another Region due to transmission limitations. Consequently, regional and subregional assessments should also be considered.

Regional Assessments

A review of the "Regional Reliability Assessments" section of the report indicates that all nine Regions are projecting adequate capacity resources. However, five Regions (ECAR, MAAC, MAIN, NPCC, and SERC), shown in Figure 12 and all within the Eastern Interconnection, have indicated the greatest likelihood of having to rely upon

Figure 12

Dependence on External or Additional Internal Resources Beyond Current Plans
(to Supply Peak Demand in the Late 1990's)

capacity resources beyond those currently planned to meet peak demand, some as early as 1995. Although a portion of these resources may be obtainable from adjoining Regions, within the limits of available transmission capabilities, it appears that in many cases additional internal resources will be needed.

The types of risk to electric supply adequacy vary among the Regions and include: the possibility of either a decline in or the inability to improve generator availability, the effects of clean air legislation, the degree of availability of emergency assistance from neighboring Regions, questionable availability of natural gas for NUGs, heavy reliance on uncommitted or unspecified capacity beginning in 1995, and either a modest increase in peak demand above forecast or the effects of extreme summer or winter weather conditions. See the "Regional Reliability Assessments" section of the report for additional information.

Capacity Resource Concerns

Many factors can impact projected capacity resources as planned by the utilities. Key among these are:

Environmental Regulations — The potential for loss of existing capacity, primarily due to possible environmental regulations, is difficult to address. The amount of loss, and the timing as well, is highly uncertain. In any event, the loss will have to be replaced to achieve the planned capacity resources necessary to meet the forecast peak demands. See the "Environmental Considerations" chapter for additional comments.

Peak Demand Exceeding Forecast — If sustained peak demand growth is greater than projected, capacity plans will have to be modified. It could take several years to confirm an increase in growth rate. It may then be too late to install baseload generating capacity, as typical baseload capacity lead times are in the range of eight years or more. Utilities may be limited to short lead-time capacity options. Even these may require three years minimum lead time. Siting considerations may also preclude a timely response except possibly for the installation of combustion turbines at existing sites.

Short Lead-time Capacity Options — Relying on short lead-time capacity options could cause many orders for generation equipment to be placed within the same short period. This equipment might require delivery at essentially the same time, which could exceed the capabilities of the equipment manufacturers to produce the equipment when needed. This, in turn, could result in some utilities seeking to rely on the capacity resources of their utility neighbors. However, these neighbors could also be facing the same capacity dilemma and not be in a position to provide sufficient assistance.

Load Management and Interruptible Demands — All Regions are projecting expanded use of direct utility-controlled load management and interruptible demand programs. During the 1989 summer and 1989/1990 winter peak demand periods, utilities in several Regions exercised their load management and interruptible demand programs to reduce peak demands. The use of these options varies among Regions due to contract arrangements and the relative need to reduce peak demand for overall system reliability.

The long-term effectiveness and customer acceptance of these programs have yet to be proven. However, utilities in MAAC, MAIN, NPCC, and SERC will be heavily dependent on the success of these programs in satisfying their generating capacity margin requirements over the next ten years, especially in the latter half of the assessment period.

Generating Capacity Availability — Several Regions are planning to improve the availability of their generating capacity during peak demand periods by eliminating or moving unit scheduled maintenance from these periods. Several have also projected improved on-peak availability of units due to reduced forced outage rates. The likelihood of these improvements being achieved varies with the Region. Should these improvements not be realized, dependence on the capacity resources in neighboring systems or other short-term resource options, either load management or new capacity, could become critical to these Regions.

Unspecified or Unknown Capacity — A review of the last five ten-year forecasts shows that unspecified or unknown planned capacity additions have increased

Table 10 — Non-Utility Generator (NUG) Capacity

	Summer 1998 NUG Capacity (as % of Total Capacity Resources)		NUG Capacity Additions (Summer — MW)
	1989-1998 Forecast	1990-1999 Forecast	1990-1999 Forecast
ECAR	2.4	2.4	2,273
ERCOT	2.2	2.1	-2,145
MAAC	7.1	8.0	3,608
MAIN	0.2	0.3	160
MAPP	1.1	1.1	0
NPCC	4.4	6.3	7,073
SERC	3.1	3.4	4,300
SPP	0.7	0.8	512
WSCC	6.3	6.7	4,184
NERC-Total	**3.6**	**4.1**	**19,965**
United States	**3.9**	**4.4**	**18,251**
Canada	**1.0**	**1.6**	**1,714**

in the United States and Canada on both an absolute magnitude and percent of total planned additions basis.

In the United States, the amount of unspecified or unknown capacity (as to fuel type) has increased from the 10,000 MW level in the 1986 and 1987 forecasts (about 12% of total planned additions) to 15,260 MW (about 18% of total planned additions) in the 1990 forecast. Similarly, in Canada, unspecified capacity has increased from about 200 MW (about 1.5% of total planned additions) in the 1986, 1987, and 1988 forecasts to 2,480 MW (about 11% of total planned additions) in the 1990 forecast.

Limiting the identification of capacity resources to only about five years into the future has become a widespread practice. This is due in part to the reliance by many utilities on short lead-time capacity supply options. There is a reliability concern that some utilities may not commit to a specific capacity supply option in time to assure that the option is available for service when needed.

Units Not Yet Under Construction — A review of planned capacity additions over the last five ten-year forecasts indicates a steady increase, particularly in the United States, in the amount of capacity not reported to be under construction at the beginning of each forecast period. Capacity not reported to be under construction in the United States has ranged from about 34,000 MW (about 40% of the total planned additions) in the 1986 forecast to about 63,000 MW (about 73%) in the 1990 forecast. In Canada, the increase has been from the 5,000 MW level to about 10,000 MW (35% to 47% of planned additions, respectively) over the same period.

This trend is understandable as previously committed longer lead-time units are being completed and the mix of future units is tending toward shorter lead-time options. However, with regard to maintaining adequate system reliability, there is concern about the increasing amount of capacity additions scheduled for service within the first two to four years of the forecast period that are not reported to be under construction.

Natural Gas Availability — A continuing utility concern is that of fuel supply. The availability and recent lower prices for natural gas, combined with relatively short construction periods, and relatively low capital costs, have made combustion turbines the predominant choice for many utilities. A sudden change in the fuel supply environment or additional governmental regulations could drastically limit fuel supplies to many of these units. This is particularly true for NUGs, many of which have interruptible fuel supply contracts. These fuel situations can reduce electric system reliability.

Fuel diversity is becoming an important reliability concern as gas-fired NUGs and utility combustion turbines become a growing portion of electric utilities' planned capacity additions. Fuel storage capability is also important. However, since many NUGs are baseload units, fuel storage may not be as feasible for NUGs as for utilities, where such units are generally used only for peaking purposes. Future regulations for nitrogen oxides (NO_x) could severely limit combustion turbine capability. See the "Fuel Supply Adequacy" chapter for additional comments.

Table 11 — Actual vs. Planned Non-Utility Generator (NUG) Additions

	1988			1989		
Region	Planned (MW)	Actual In Service (MW)	Success (%)	Planned (MW)	Actual In Service (MW)	Success (%)
ECAR	27	27	100	107	97	91
ERCOT	0	0	—	468	406	87
MAAC	506	221	44	307	159	52
MAIN	0	0	—	0	0	—
MAPP	17	17	100	45	45	100
NPCC	448	316	71	573	429	75
SERC	1,071	685	64	19	19	100
SPP	0	0	—	100	100	100
WSCC	1,883	1,675	89	1,612	1,665	103
Total	**3,952**	**2,941**	**74**	**3,231**	**2,920**	**90**

Reliance on NUGs — A further concern is the increased reliance on non-utility generators (NUGs). The amount of NUG capacity that utilities are including in their capacity plans is increasing. This is shown in Table 10. The impact of NUGs is not uniform across the United States. About 42% of existing and planned NUG capacity in the United States is in California, Texas, and New York.

In WSCC, 4,184 MW or about 34% of the planned capacity additions over the 1990-1999 period are projected to be NUGs. Similarly, 3,608 MW in MAAC (or 35% of its planned capacity additions) and 7,073 MW in NPCC (or 24% of its planned capacity additions) are projected over the 1990-1999 period to be NUG capacity. With the increasing dependence on NUG capacity, utilities are carefully assessing the amount of this capacity that will actually be available to serve future customer demands.

NUG plans and commitments are not always realized. Table 11 shows utility experience with NUGs in 1988 and 1989. Of the 3,952 MW expected to come on-line in 1988, 2,941 MW or 74% were actually available for service by the end of the year. Similarly, of 3,231 MW expected in 1989, 2,920 MW or 90% were actually available. From this, it can be concluded that NUG owners are not immune to similar problems faced by electric utilities in getting generating units sited, permitted, constructed, tested, and on-line as scheduled.

Transmission Reliability Assessment

The existing electric transmission systems and the systems as planned over the next ten years are judged to be generally adequate to reliably meet customer electricity requirements. However, reliability concerns exist in some areas where transmission facilities have not been allowed to be constructed as planned. Specific areas where transmission reliability is of concern are ERCOT, MAAC, MAIN, and SERC.

The complexity of operating the transmission systems will continue to increase as utilities maximize the use of existing facilities. Utilities are seeking ways to deal with this complexity through improvements in monitoring, more widespread information exchange, improved control and coordination, increased and more rapid on-line analysis, and enhanced operator training.

The future reliability of the transmission systems depends on siting and constructing new facilities in a timely manner where required. Because of the history of disincentives and delays involved with constructing new transmission, there is concern that future transmission capability will not meet the need in some areas. The result could be unsatisfactory reliability due to limited transfer capabilities and continuously heavy transmission loadings in these areas.

Adequacy of Transmission Systems

Electric utilities within each Region continually assess the ability of their internal transmission systems and interconnections with other systems to meet their individual reliability criteria. These assessments are based on both short- and long-term needs. To complete these evaluations, Regions also participate in joint studies with adjacent Regions. These intraregional and interregional studies measure overall system strength and capability that are used to judge future transmission system adequacy.

Bulk electric transmission systems as currently planned are generally expected to be adequate during the next ten years. However, reliability concerns exist in certain areas of ERCOT, MAAC, MAIN, and SERC where transmission facilities have not been allowed to be constructed as planned or where the use of the transmission system is changed relative to that which was planned, leaving little room for additional unforeseen electricity transfers.

Interconnections and Electricity Transfer Capabilities

The bulk electric transmission systems are essential to providing reliable electric service to the millions of customers throughout the nine NERC Regions. Early in the development of these systems, it was recognized that reliability of electric service could be improved with the development of transmission interconnections and the sharing of generating capacity resources among individual systems. For example, if one system experiences a generation deficiency, replacement generation may be available from one or more neighboring systems via interconnecting transmission lines. However, if adequate transmission interconnection capability does not exist, the system with deficient generation would not be able to serve all of its customers' electricity demands.

The actual operation of electric transmission systems is more complex than this simple example. However, the example illustrates the basic concepts upon which the interconnected electric transmission systems have evolved. The system in the example would in general have had to plan for a higher level of generating capacity resources as a single independent system than as part of a larger interconnected system. The economic benefits of reduced generating capacity requirements along with increased reliability are the fundamental reasons for establishing transmission interconnections. Aside from these emergency aspects, transmission interconnections permit economic optimization of generating resource utilization on a day-to-day and hour-to-hour basis.

Today, the interconnected bulk transmission systems of NERC comprise thousands of circuit miles of transmission lines rated 230 kV and above. Transmission interconnections link all of the NERC Regional Reliability Councils as illustrated in Figure 13. Some interconnections are viewed as being "stronger" than others based upon the amount of electricity ("transfer capability") that can safely and reliably flow from system to system over the interconnected transmission lines.

The transfer capability of an interconnection is <u>not</u> a fixed value. It is based upon many different factors that can cause the transfer capability to change such as generation dispatch, customer demand levels, voltage profiles, availability of equipment, and ambient temperatures. The transfer capabilities depicted in Figure 13 are representative of the maximum incremental non-simultaneous transfer capabilities that have been determined from one particular set of system conditions. Conditions as studied may not exist at the time of need and the indicated transfer capabilities may not be fully available.

Planned Transmission Additions

The transmission circuit mile additions projected for the future are an indicator of the relative strengthening of the transmission systems. The projected additions in transmission circuit miles by voltage class are depicted in Figures 14 and 15 for the United States and Canada, respectively, over the assessment period. Although the addition of transmission cir-

Figure 13

Normal Base Power Transfers and First Contingency Incremental Non-Simultaneous Transfer Capabilities Summer 1990 - MW

(Extracted from NERC's 1990 Summer Assessment Report)

A. The Hydro-Québec export is limited to 1,700-2,200 MW on the combined three HVDC interconnections due to the Hydro-Québec system contingency.

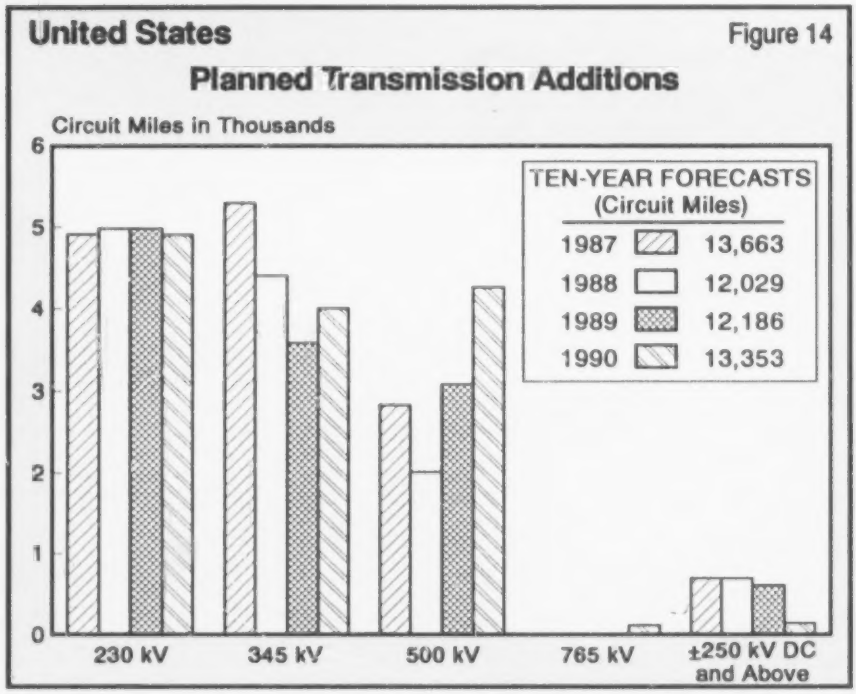
B. The only transactions between Ontario Hydro and Hydro-Québec consist of isolated demand and generation; there are no synchronous ac ties or back-to-back HVDC interconnections between the two systems. A maximum of 1,400 MW can be isolated onto the Ontario system by Québec and 600 MW can be isolated onto Québec by Ontario.

C. The maximum export from New Brunswick and New England to Hydro-Québec must not exceed 900 MW. The New York Power Pool has demonstrated a non-simultaneous, independent transfer capability of 1,000 MW to Québec.

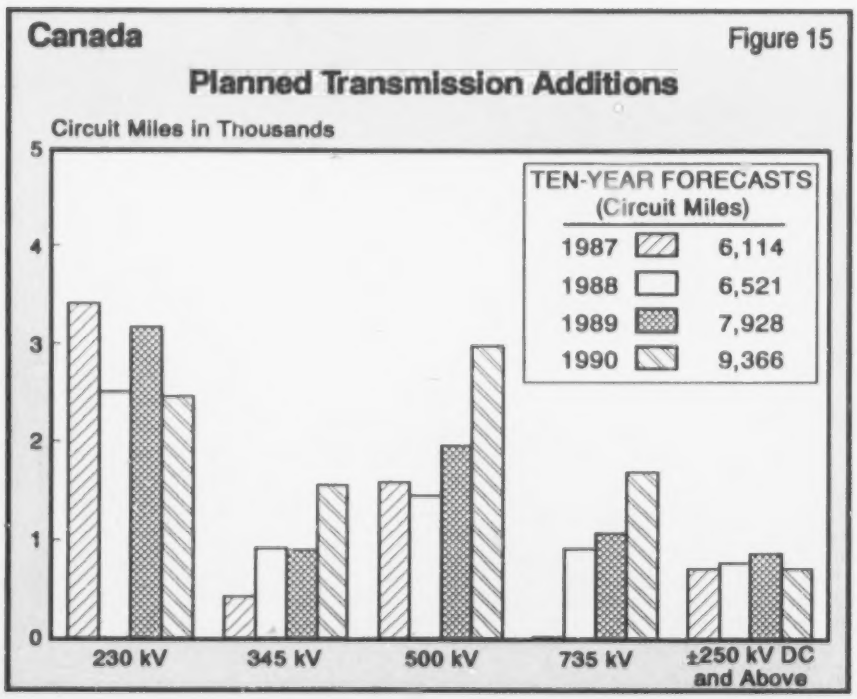
* Those values shown with an asterisk (*) are First Contingency Total Transfer Capabilities – the total amount of electricity that can be transferred over the transmission network in a reliable manner.

** Indicates that an operating rule must be in effect to allow the noted capability to be used.

\+ Indicates no significant transmission limit found at this level.



cuit miles indicates a positive reinforcement of the interconnected systems, the associated increased use of transmission systems due to increased demand growth, generation additions, generation deficiencies, and the increasingly competitive bulk power market must also be considered in evaluating overall system strength and reliability.



Increased Simultaneous Electricity Transfers

The transfer capabilities depicted in Figure 13 are non-simultaneous capabilities. This means that it is unlikely that any two or more of the transfers can be achieved at their maximum potential at the same time and still comply with reliability criteria.

Determining simultaneous transfer limits is a complex process that involves detailed modeling of a large number of anticipated system operating conditions. Operating procedures are developed based upon the results of a range of these technical studies and operational experience to help ensure that the simultaneous transfer limits are not exceeded. In some cases, it is necessary to construct additional transmission lines or rely on special protection systems or coordination agreements to relieve the simultaneous transfer limitations and still meet reliability criteria.

A number of factors over the past few years have contributed to a trend of operating the transmission systems at higher transfer levels, and for longer periods of time. These increased transfers are the result, in part, of utility interchange of economically-priced electric energy and capacity to achieve operating efficiency, to defer utility generating units, or to deliver non-utility generation. Additional factors, contributing to the increased use of the transmission systems, which are described in more detail in other sections of this report, include disincentives to constructing new generating plants and uncertainty in forecasting the growth in the demand for electricity.

The electric systems should be operated at all times so that they are able to sustain the sudden loss of a single transmission line, generator, or any other critical piece of equipment. If transfer capabilities are exceeded, there is a serious risk that the sudden outage of equipment could create widespread uncontrolled interruption of electric service.

As more and more transmission paths are stressed to maximum levels at the same time, the complexity of establishing new simultaneous transfer limits that consider the more probable operating

combinations increases significantly. As it is impossible to thoroughly assess all possible operating conditions — combinations of facilities out of service, combinations of transfers that may be maximized at the same time, varying generation patterns, and other variables — there is risk that a particular operating condition can occur that has not been studied, which could jeopardize reliability.

Procedures that must be followed by system operators become more significant as the transmission systems are loaded to higher levels. The risk of operator error increases with the increased complexity of operating procedures. Additionally, the consequences of operator error become greater as the transmission network is operated at higher loading levels.

Further, as the transmission systems are operated at higher and higher loading levels, the flexibility of the transmission systems to successfully accommodate severe disturbances, such as the loss of multiple transmission lines, is diminished. The situation is similar to that of a person walking near the edge of a cliff. As long as the person maintains a comfortable distance from the edge, any trip, stumble, or fall is not likely to have a serious consequence. However, as the person draws ever nearer to the edge, the consequences of a trip, stumble, or fall become increasingly more serious. Operating the transmission systems at increasingly higher loading and transfer levels is analogous to approaching the edge of the cliff. The overlapping forced outage of multiple transmission lines during conditions of heavy transmission loading has the potential to cause widespread outages of electric service.

Timely installation of new transmission facilities as planned will reduce the risks associated with heavy simultaneous transfers and potential operator errors, and will help in maintaining a safe distance from the edge of the cliff.

Special Protection Systems

Reliance upon special protection systems (SPSs), or remedial action schemes, in those instances where additional transmission lines cannot be built or have been delayed also poses an element of risk to electric system reliability. SPSs are advantageous in that they are far less costly and are not subject to the environmental concerns associated with siting and building a new transmission line. Under certain conditions, the use of SPSs in lieu of new transmission lines is quite appropriate. However, the SPSs must be highly reliable, as the consequences of their failure to operate when called upon could include widespread interruption of electric service.

Within WSCC, a review procedure has been established to evaluate the design and application of individual SPSs in an effort to assess the consequences of failure and minimize the probability of failure. NPCC has also approved guide-

HIGH VOLTAGE AC ELECTRICAL TRANSMISSION SYSTEMS

The high voltage alternating current (ac) transmission systems or electrical networks presently used for the transportation or "transfer" of electricity are fundamentally different from transmission or transportation systems used for the movement of commodities or products of commerce. This is because — unlike gas or oil in pipes, grain in railroad cars, traffic on the highway — electricity is not readily routed over specific transmission paths on the ac network in place today. Electricity must be produced on demand and cannot yet be economically stored.

In gas transmission systems, oil pipelines, railroad or highway systems, the "flow" in any segment or along any route can be directly controlled by valves, gates, or traffic lights. When a transfer of electricity is made, it generally cannot be directed down certain transmission "paths" to follow pre-determined routes. Rather, the distribution of electricity flow in each path from generator source to the area of need, or customer demand, is solely a function of the electrical characteristics of the transmission lines and transformers in each path relative to other paths in the network. That is, electricity will use, to varying degrees, all available transmission line "paths" between two areas in a system to effect a transfer since electricity follows the immutable laws of physics, rather than human laws or contract paths.

Because of the number of components and physical size of the interconnections in North America, the number of electricity flow patterns possible is almost infinite. In addition, the interrelated configurations of generators and transmission lines are constantly changing. This, combined with the instantaneous variations in customer demand, causes the pattern of electricity flow to change at every instant.

Since the flow of electricity cannot be made to readily follow pre-determined paths, and since the pattern of flow on the transmission systems or networks is constantly changing, it is not surprising that the capability of the transmission system to transfer electricity from one point to another is not easily defined. In fact, the capability cannot be specified by a single value. Like the pattern of flow on the network itself, the capability to transfer electricity changes continually.

While "transfer capabilities" between one system and another are often quoted, it is understood by those who determine them, and those who use them, that these capabilities are approximations for a specific set of conditions and not firm values that apply at all times. Therefore, a published "transfer capability" should be regarded more as a typical or average value. The actual capability at any moment may be considerably higher or considerably lower.

SPECIAL PROTECTION SYSTEMS

Special Protection Systems (SPSs), or Remedial Action Schemes, are designed to perform system protection functions other than the isolation of electrical faults. Typically, SPSs trip loads, generators, or additional transmission facilities.

SPSs are installed to operate in contingency situations to permit higher levels of electricity flow on the transmission systems in those instances where additional facilities cannot be built, or have been delayed. They may be used to maintain system stability or control loadings on critical facilities immediately following a system disturbance or other abnormality on the system. SPSs may also allow higher electricity transfers and the use of more economic generation. However, they can expose a system to greater reliability risks since the integrity of the system depends on their correct operation.

lines regarding the application of SPSs. The NPCC guidelines define three applications of SPSs based on their transmission system impact, and specify design requirements for each type.

At this time, the use of SPSs is not considered to be an issue of serious concern with respect to maintaining reliability. The issue will continue to be monitored, however, as the potential for concern exists, particularly as the reliance upon and the complexity of SPSs continue to increase.

Opposition to Transmission

Within some Regions, the opposition to the construction of new transmission lines is having an adverse effect upon reliability. Reliability concerns exist in certain areas of ERCOT, MAAC, MAIN, and SERC where transmission facilities have not been allowed to be constructed as planned.

- ERCOT — Application for certification of the 55-mile, double circuit **Salem-Zenith 345 kV line** was in the regulatory certification process for over four years before finally being rejected by the Texas Public Utility Commission (PUC) due to routing issues. The line is needed to increase emergency transfer capability within ERCOT, to deliver electrical energy from remote generation, and to provide for economy

USES OF TRANSMISSION SYSTEMS

The network of bulk electric transmission systems provides several functions that are vital to the reliability and adequacy of electric supply systems. The major uses of bulk transmission systems are to:

- Deliver generation to load centers — Satisfactory generation sites are often remote from load centers. Transmission systems are required to provide a reliable connection among remote generators and customer load centers.

- Provide flexibility for contingencies — Transmission systems and interconnections provide flexibility to deal with system emergencies and uncertainties such as outages of generation or transmission equipment, construction delays, higher than expected customer demand, and fuel shortages or disruptions.

- Reduce installed generating capacity — Transmission interconnections among utility systems allow utilities to share generating capacity through diversity in peak demand and generator availability. Sharing generating capability required for adequate reliability significantly reduces each utility's investment in generating facilities.

- Allow economic sharing of generation among systems — Transmission interconnections among utilities allow use of the most economic generation resources while maintaining reliability. Electric utility customers benefit because the lowest cost generation is dispatched to supply their electricity needs.

Many interconnected transmission systems were originally designed to primarily provide reliability through emergency transfer capability assistance among utilities. In this sense, the transmission system is a generation resource in that it provides access to a large source of generating capacity. For example, a large independent power pool may require about 35% capacity margin if it were not interconnected with other systems or Regions. But with sufficient transmission ties to available generating capacity in an adjacent large system, it may only require 25% capacity margin for the same level of reliability. The capacity value of transmission ties to the large system is ten percentage points in this case. It is important that generation and transmission planners work together to assure the proper generation-transmission planning and operating coordination.

In the past, large capacity or energy transfers on the transmission systems were only expected to occur during critical component outages or system emergencies. However, in recent years, these same transmission systems have been routinely used for significant amounts of interregional electricity transfers driven by economics instead of emergency assistance. The transmission systems have performed this economic function quite well. The increased role of these economic transfers may well change the projections for future transmission additions.

energy and firm capacity transfers. Subsequent rulings by a State District Court and an Appeals Court ordered the Texas PUC to reexamine the findings of fact in the case. Intervenors appealed the decisions to the State Supreme Court, which in September 1990 returned the case to the lower court for a detailed evidentiary review.

- MAAC — Despite recent progress in overcoming obstacles in the approvals process, the long delay in completion of the **Baltimore-Washington 500 kV loop** stands as a classic example of the inability of U.S. utilities to achieve timely installation of critical transmission facilities. This project originally scheduled for 1974 is now scheduled for completion in 1994. Had the Baltimore-Washington 500 kV loop been in service on July 5, 1990 when peak customer demands and outages of key generating facilities in the Baltimore-Washington area combined to stress transmission capabilities, it is considerably less likely that the affected utilities would have had to implement customer interruptions totalling 400 MW to maintain system reliability. General opposition to the construction of new transmission within the Region, most notably the **Red Bank-Taylor Lane-Aberdeen 230 kV line** in New Jersey, is of concern. Possible system reinforcements and potential operating procedures to increase the interregional transfer capabilities are being studied. With the reliability constraints that sometimes appear on the interconnected transmission systems, the MAAC Region's operating reliability is at times below desired levels.

- MAIN — The **Albion-E. West Frankfort 345 kV line** was originally scheduled for completion in 1990. However, due to a lengthy regulatory approvals process, court action required before condemnation, and probable future court actions, the line will probably not be placed in service until 1992. This line will constitute a third 345 kV circuit across southern Illinois and is needed to reinforce the electric supply capability to a large area of southeastern Illinois.

- SERC — The **Lake Tarpon-Kathleen 500 kV line** in Florida had been delayed because of a state-initiated review of the electric and magnetic fields (EMF) issue. Construction of the line, originally scheduled for completion in December 1987, is proceeding under new EMF guidelines. Until the line is placed in service, higher cost local generation will be operated to maintain system reliability. As area demand increases in the early 1990s, the continued uneconomic operation of local generation will become ineffective in maintaining reliability.

In some areas, regulatory pressure is influencing electric utilities to provide only the minimum facilities needed in the short term. The result is a transmission system loaded near to its capability and, therefore, one that is sensitive to small changes in operating conditions. Because of this, owners of transmission are becoming more concerned about their diminishing transmission capability margins.

If regulatory bodies require, as in California, that firm contracts for electricity transfers on a new transmission line be established as a condition for justifying and authorizing the line, there may not be sufficient reserve transmission capability to accommodate emergency requirements, much less future transmission service for non-utilities and utilities.

The transmission systems are exposed to a wide range of system operating conditions, and on rare occasions, the systems may be pushed beyond their limits by unforeseen events.

Geomagnetic Disturbances

As demonstrated by past events, some as recent as March 1989, unusually large bursts of charged particles emanating from the sun can affect the earth's magnetic field with sufficient intensity to induce electrical currents on the transmission systems that can cause damage to equipment and adversely affect system reliability. Restoration of electric service disrupted by these geomagnetic disturbances (GMDs) can be delayed due to equipment damage.

GEOMAGNETIC DISTURBANCES

Geomagnetic Disturbances (GMDs) occur during periods of high sunspot activity. Solar flares produce bursts of charged particles, primarily protons and electrons, that are emitted in all directions from the sun. This "solar wind" interacts with the earth's magnetic field and can have a disruptive effect on electric systems.

Currents induced by the perturbations to the earth's magnetic field enter the electric systems through the grounded neutrals of transformers. The effects are more intense near the earth's poles and where ground resistance is high. Consequently, electric systems in the northern latitudes over igneous rock formations are more vulnerable. The induced currents can cause transformer cores to saturate leading to system voltage regulation problems, protective relay problems, and possible overheating and damage to the transformers themselves.

The intensity of solar flare activity fluctuates over time, peaking in approximately 11-year cycles. The current sunspot cycle will reach its peak during late 1990 or early 1991. Historically, GMDs have reached their peak activity two to three years after the sunspot cycle peak.

Warnings regarding geomagnetic storm intensity are provided to the electric utilities by the Space Environment Services Center of the U.S. National Oceanic and Atmospheric Administration and the Bureau of Energy, Mines, and Resources of Canada.

Electric utilities can take some precautionary measures to reduce the impact of GMDs by changing the settings of protective relays to make them less sensitive to GMD induced currents, by reducing electricity transfers, and by providing additional reactive support to maintain desired voltage levels.

In an effort to avoid system collapse resulting from GMDs, some relay protection systems have been desensitized to geomagnetically induced currents. Research is in progress to determine what other actions can be taken to desensitize the network to the GMD effects. Utilities throughout NERC also receive forecasts of GMDs to enable them to take appropriate precautions. However, the accuracy of the present warning system is in question.

Voltage Stability

Voltage stability is an issue that continues to receive careful study by electric utilities. It has become of particular significance as transmission loadings reach higher levels and as electricity is transferred over greater distances.

The advance determination, monitoring, and control of voltage related limits require special attention because system operators may not have sufficient time to avert voltage collapse once a disturbance has been initiated. In addition, the critical facility failure or misoperation that affects voltage stability could be remote from the utility that experiences the largest voltage decrease. As a result, this type of situation is difficult to detect and could go unrecognized until a disturbance occurs. If planning studies detect such a problem, the appropriate monitoring and communication procedures can be implemented for system operators. Coordination in planning and operating the electric systems is vital to maintaining adequate system reliability, especially when long-distance electricity transfers are common.

As an example of this potential reliability problem, portions of the transmission systems within the Pacific Northwest are being loaded heavily during winter peak demand periods. Study results indicate that during transmission line outage conditions there is a risk of voltage instability occurring which could lead to uncontrolled loss of customer demands. The condition will become more severe as customer electricity demand continues to increase. Operational procedures are now in place to monitor line loadings and to take preventive actions such as bringing local generators into service for additional voltage support and to reduce transmission loadings. The utilities in the Pacific Northwest are now embarked on a major study of long-term solutions to the problem.

Parallel Path (Loop) Flow

Because of the nature of ac transmission systems, electricity transfers between two systems can cause flows on parallel transmission paths in other interconnected systems not directly involved in the transfers. These flows make it difficult to analyze system capability and performance because the sources and effects of the multiple transfers are not easily determined. The wide range of electricity transfer possibilities creates a myriad of conditions to study, monitor, and control.

A number of utilities are attempting to minimize the effects of parallel path flow and maximize the use of their transmission systems by adding control devices such as phase-shifting transformers, series capacitors, and series reactors. These devices help to redirect line flows but may not totally eliminate the problems caused by parallel path flow. Instead, the problems may be moved to another part of the system or someone else's system. Addition of these devices and their proper operation require close coordination as well as good communications among electric system operators. These devices add to the complexity of analyzing and operating the transmission network reliably.

Non-Utility Transmission

In a few areas, transmission lines have been built by non-utility generators (NUGs) to deliver their electrical output to the utility systems. To date, most of these non-utility lines are connected radially from the NUG to the utility network, posing no particular problem from a transmission reliability perspective. However, if the non-utility transmission lines are further integrated into the utility network and are no longer radial, potential reliability problems can arise if these lines are not designed and operated in compliance with regional reliability criteria. Close coordination, joint planning, and operating arrangements are required to assure that all transmission, both utility and non-utility, complies with reliability criteria and will not cause adverse safety and reliability effects on overall system operations.

Transmission System Services

The degree to which utilities may be required to provide transmission service for others (both utilities and non-utilities) is an issue that potentially threatens future electric system reliability by further increasing transmission system loadings, reducing transmission capability margins, and increasing coordination problems.

Transmission systems were not designed to provide unlimited transmission service for all parties. It is imperative that any future policies regarding use of the transmission systems recognize the need to maintain adequate electric system reliability.

All participants utilizing the transmission systems must adhere to accepted planning and operating policies and practices designed to maintain electric system reliability as described in the NERC Policies, Criteria, and Guides as well as in regional and individual utility policies and practices.

Reliability Issues
Demand Forecast Uncertainty

Accurate electricity demand forecasts are particularly important to electric system reliability as utilities strive to maintain the most economical long-term supply/demand relationship. Despite the need, accurate demand forecasts are very difficult to make because they are affected by many factors that cannot be predicted with assured accuracy. The recent trend of actual peak demands exceeding forecasts underscores this difficulty.

Weather, the economy, the price of electricity, and the future effects of conservation all affect future customer demand, but each is very difficult to project. Utilities recognize the problems in forecasting and are striving to make predictions as representative of the future as possible. Underestimating the future demand for electricity can lead to supply shortfalls.

Demand Forecasts

Forecasts have a vital impact on electric system reliability. Peak demand forecasts, together with capacity projections, are used to ascertain the need and timing for new generating capacity, demand management, and utility capacity purchases and sales. As annual electrical energy use is considered less sensitive than peak demand to extreme weather effects and more closely tracks economic variables, electrical energy forecasts are often the basis for peak demand forecasts. Electrical energy forecasts are also used as a basis for fuel procurement and financial projections. Therefore, both peak demand and electrical energy forecasts are extremely important to electric utility planning and operations.

Because generating capacity margins in many areas of the United States and Canada are decreasing, concern about forecast accuracy is increasing. The proper timing for capacity and demand management additions depends on accurate demand forecasts. Financial and regulatory constraints emphasize the need for optimal timing of resource additions.

With regional forecasts of peak demand growth over the next ten years varying from 1.4 to 2.7%, small forecast errors consistently in the same direction can produce a major cumulative effect on projected peak demand levels. Fifteen to twenty years ago, when utilities were experiencing a 5 to 7% annual growth rate, a one percentage point error for a number of years had less of an effect on future capacity plan additions than a one percentage point error does now. Formerly, the one percentage point error in growth rate would have affected about one-sixth of the total peak demand forecast, now it impacts half of the forecast.

During the late 1970s and early 1980s, most electric utility peak demand forecasts were generally greater than actual peak demand growth. While this trend eventually resulted in more than minimum capacity margins, it had the advantage of improving system reliability. However, over the last five years, a number of Regions have experienced peak demands which even after weather adjustment have exceeded forecasts. If this trend becomes widespread and continues, it will adversely affect reliability of electric supply to customers. Underestimating the future demand for electricity can lead to supply shortfalls.

Peak demand forecasts are based on a myriad of factors, none of which can be predicted precisely. Therefore, demand forecasts cannot be perfect; some forecast error is inevitable. Forecast bandwidths are often used to show an expected range in forecast uncertainty. Estimated bandwidths for the projected 1990-1999 peak demands for the United States and Canada are discussed in the "Peak Demand Projections" chapter. Several of the key factors that have a major effect on peak demand forecasts are discussed below.

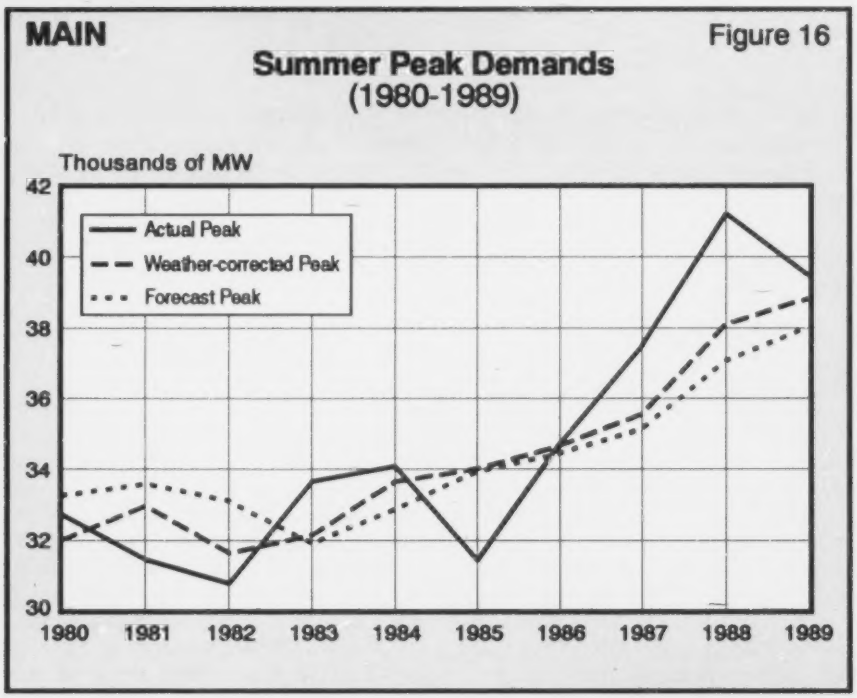
Weather

When comparing forecast and actual peak demands, weather effects often cause the forecast peak demands to seem less accurate than they are. Adjustment of peak demands experienced during extreme weather conditions to equivalent peak demands based on average or normal weather conditions helps to eliminate a major source of apparent discrepancy between forecast and actual peak demands. This weather normalization is illustrated in Figures 16 and 17, where actual and temperature-corrected peak demands in two Regions are shown along with their peak demand forecasts made a year earlier. In recent years, the weather-corrected actual peak demands are much closer to the forecasts than the uncorrected actual peak demands first indicate. However, the weather-corrected actual demands have still exceeded previous year forecasts.

The 1988 summer was unusually hot, which caused the uncorrected actual peak demands to exceed their forecasts in all nine Regions. The uncorrected U.S. aggregated actual peak demand for 1988 exceeded the high bound of the U.S. estimated 80% probability forecast bandwidth developed a year earlier. The 1989 summer was generally more moderate and the 1989 uncorrected U.S. aggregated actual peak demand was essentially on forecast, but still actual peak demands in six of nine Regions were above forecast.

Use of weather normalized forecast peak demands recognizes that supplying demand above the basic design level can only be accomplished if adequate capacity margins are available. Therefore, utility capacity margin requirements generally include an allowance for serving customer demands resulting from reasonably anticipated, but generally not extreme, weather variations.

The 1989/90 winter had periods of abnormal cold, illustrating once again the impact weather has on peak demands.



Customer demands well above those expected during normal winter weather conditions caused rotating blackouts in Texas and Florida, and voluntary customer demand curtailments in Ontario.

Temperature extremes cause many customers to purchase auxiliary cooling/heating equipment to assure their comfort under abnormal temperature extremes. As a recent example, a survey by Florida Power & Light Company of retail outlets selling strip-heaters indicated that 400 to 500 MW of electric heating capacity were purchased during the unseasonably cold weather in Florida in December 1989. Most likely these units will have an impact on future winter peak demands in Florida especially when abnormally low temperatures occur.

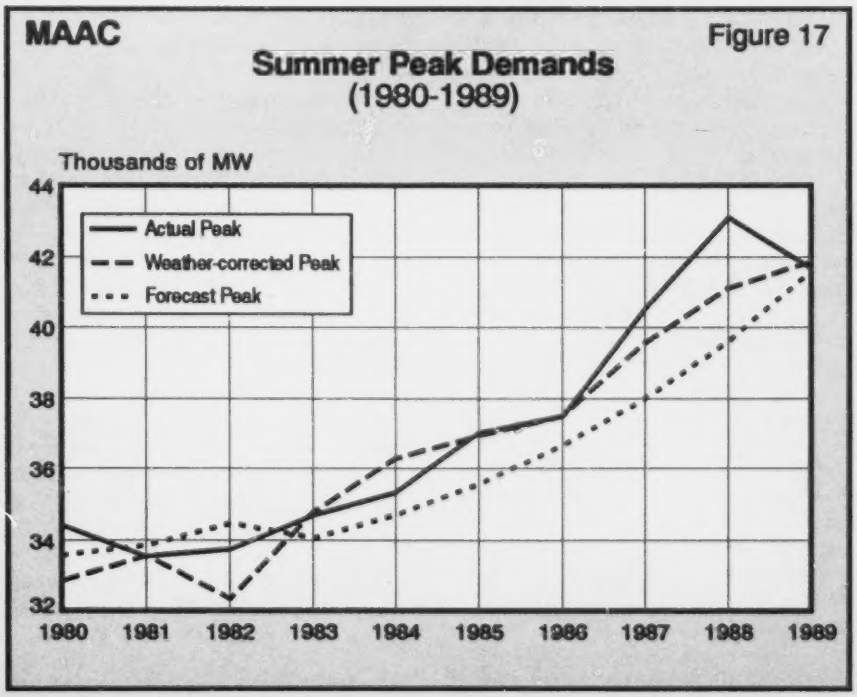


Figure 18 shows peak demand forecast deviation from uncorrected actual summer peak demand for the United States. Curves are shown for forecasts ten, five, two, and one year prior to each specific year. In the aggregate, the U.S. one- and two-year forecasts have been quite accurate since 1983, with the exception of 1988, when summer temperatures were abnormally high. Due to the length of the forecast period and the changing economic conditions, the ten- and five-year forecasts are less accurate than the short-term forecasts, but reflect a trend toward improved accuracy.

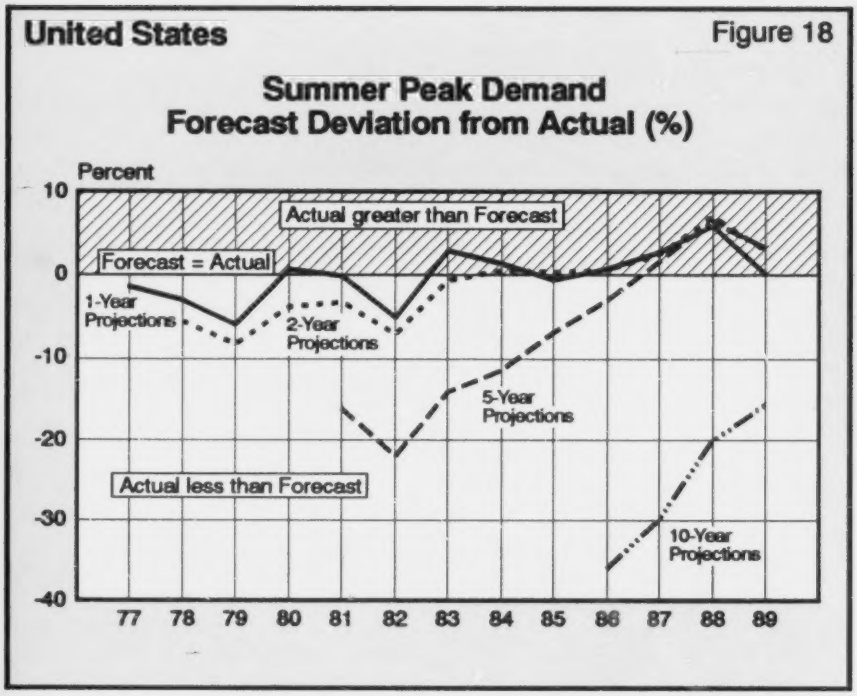
National and Local Economies

The state of the local and national economies also has an important influence on the electrical peak demands experienced by utilities. Generally, projections of gross national product (GNP), or its local equivalent, are factored into the demand forecasts because of the historical relationship between GNP and electrical energy consumption. However, there are also wide variations in GNP projections, and the relationship between GNP and electrical energy consumption is also subject to variation.

Employment and Demographics

High levels of employment are a measure of prosperity, which is a significant factor in electrical energy consumption. For example, either high levels of unemployment, or fears of hard times ahead, will deter many from using air conditioning equipment to the extent they would when the economy is strong and job security is not a major concern. There are numerous examples of a sudden, unexpected increase in customer demand due to air conditioning following several years of economic recession. These factors are difficult to quantify and very difficult to predict, and, therefore, also contribute along with weather to demand forecast uncertainty.

Changes in population can be cyclical, such as the much publicized "baby boom" after World War II. Relocation of population with corresponding changes in the electrical energy intensiveness of



developing areas also affects demand growth.

Price of Electricity

The magnitude of electricity use is inversely related to its real price. The prime example of this was the oil embargo in 1973 that resulted in greatly increased energy prices and the decline in the rate of growth of electric peak demand. Also, the immutable supply vs. demand effects on energy prices were visible late in 1989 when gas and oil prices escalated rapidly as a result of the December cold. Forecasting oil and natural gas supplies and demands and resulting prices is not an exact science, especially since over 40% of the oil consumed in the United States is imported. Couple this with the uncertainties in the cost of electricity due to pending clean air legislation, and the problems in factoring energy costs into electricity demand forecasts becomes readily apparent.

Utility Marketing Efforts

Electric utility marketing strategies also have an effect on customer demand. Because these strategies are instituted by the utility, the effect on customer demand should be much more readily predictable than weather and economic effects. However, utility-instituted measures such as conservation and load management very likely will increase the difficulty in developing accurate peak demand forecasts.

Conservation

Many utilities now adjust their internal peak demand forecasts to reflect demand reductions estimated to be achievable through conservation and other demand management programs. Reduction in customer demand due to increased insulation and the increased use of higher efficiency appliances are examples of the conservation components of demand management. Some utilities do not separately list peak demand reductions due to these measures, but include their estimated effects intrinsically in their basic demand forecast. Thus, the actual demand reduction due to conservation efforts constitutes another factor adding to the difficulty in demand forecasting. If the effects of these programs could be measured, opportunities for comparison with estimates by others would be available, and perhaps the combined experience would lead to improved projections. However, the hardest demand to measure is the demand that is not served.

Load Management

The effects of load management, the operator-controlled component of demand management, are much more readily determinable than conservation effects. Tests can be performed to determine the impact of the sequential switching of air conditioners, electric water heaters, irrigation pumps, pool heaters, and similar equipment. Therefore, utilities are in a much better position to estimate the effects of load management measures on the demand for electricity.

Reliability Issues
Environmental Considerations

From an environmental standpoint, the most significant threat to reliability is the impending amendment of the U.S. Clean Air Act. This legislative effort appears to be advancing with little regard for the profound effects it will have on the adequacy of installed generating capacity, the ability and/or inclination of utilities to render emergency assistance to neighboring systems, and the viability of capacity transactions as a resource option.

Proposed regulations related to electric and magnetic fields have the potential for adversely impacting electric system reliability. Limits on carbon dioxide emissions (greenhouse effect) and further restrictions on utility use of water resources can also have significant impacts on fossil-fired and hydroelectric generation. These issues can reduce existing generating capacity, delay construction of new facilities, and increase operating complexity.

Overly stringent environmental requirements may reduce electric service reliability and increase costs to customers without achieving any significant environmental or health benefits. Therefore, it is important that utilities and public policymakers work together to provide a safe, reliable, and economic electricity supply while protecting the environment.

Environmental Issues

There is a growing concern among the general public, environmental groups, and public policymakers regarding the impacts of electricity production and delivery on the environment. These concerns relate to both existing and future generation and transmission facilities.

Electric utilities recognize the need for environmental protection and continue to implement measures to minimize the impacts of construction and operation of electrical generation and transmission facilities on the environment. However, increased environmental concerns as well as changes to environmental regulations have the potential to adversely affect electric system reliability and cost. These effects include delays in the approval or commissioning of new facilities and constraints on the operation of existing facilities. These delays and constraints will reduce capacity margins and increase the risk of customer service interruptions until the deficiencies can be corrected. The resultant impacts on system reliability and costs may have negative effects on electricity use, economic growth, lifestyles, and the standard of living.

Environmental regulations should be carefully developed with sound technical evaluations of their potential costs, benefits, and impacts on the environment and on electric system reliability. Overly stringent environmental requirements may have adverse system reliability and economic effects with little or no significant environmental or health benefits. Electric utilities are increasing their efforts in providing the public and policymakers with easily understood information on environmental issues and their effects on the reliability of electric systems, electricity costs, and the environment.

Some of the key environmental issues that have current or potential impacts on existing or future generation and transmission facilities are discussed below.

Acid Gas Emissions

Regulations exist in both the United States and Canada that limit the emissions of the acid gases, sulfur dioxide (SO_2) and nitrogen oxides (NO_x), produced by fossil-fired utility power plants. In the United States, the 1970 Clean Air Act applies to generating capacity for which construction was commenced after August 17, 1971, and limits the acid gas emissions on an individual point source basis. In Canada, a federal/provincial agreement is aimed at achieving by 1994, about a 50% reduction of the peak levels of acid gas emissions experienced in 1980. Each province has enacted legislation in line with this agreement.

In response to this legislation, electric utilities in both the United States and Canada have taken and will continue to take measures to reduce acid gas emissions from power plants burning fossil fuels. These measures include using lower sulfur fuels, installation of emissions control equipment such as flue gas "scrubbers," and research and development into new clean coal-burning technologies such as integrated (coal) gasification combined cycle and fluidized bed combustion.

The effects of acid rain due to acid gas emissions continue to be a major public and political concern with increasing pressure to enact more stringent legislation. Both the U.S. House of Representatives and Senate have passed amendments to the U.S. Clean Air Act. The U.S. Senate version of the legislation (S.1630), for example, has the potential for requiring approximately 7,500 MW of additional generating capacity by 1999 to offset the lower anticipated availability of some generating units subject to compliance regulations and to replace capacity reductions. The Eastern Interconnection would bear most of the brunt as about 92% of the effects are postulated to be in that area. Included in this legislation is a mechanism for emissions credit trading and a set of caps on those emissions. The impact that these caps might have on inhibiting the use of coal-fired generators in one area or system to provide assistance to another area or system is uncertain at this time. The overall impact of these amendments will need to be addressed when the final form of the legislation is known.

The capacity reductions would be due to premature retirement of generator units and electrical energy consumption by the additional emissions control equipment. The premature retirements would occur due to long-term economics favoring the replacement of aging units with newer, more efficient, and cleaner technology rather than renovating the aging units and retrofitting emissions control equipment to comply with the new legislation. The reliability of systems with a large proportion of these older coal units could decline due to the long lead times to put replacement generating capacity into service. In addition to the reliability impacts due to capacity deficiencies, there will be significant electricity cost increases to the customer due to the costs of additional emissions control facilities. These costs for a large coal-based utility or Region could range from several hundred million dollars to over a billion dollars during the next ten years.

New NO_x emissions regulations could be more restrictive than the regulations on SO_2 emissions. For example, the United States and Canada have signed an international protocol agreeing to keep NO_x emissions below 1987 levels. Tighter NO_x regulations will not only affect coal-fired generating units but they will also affect low sulfur oil-fired generators and both utility and non-utility gas-fired generators, including combustion turbines.

Proposed regulations on NO_x emissions in the northeastern states could limit the operation of peaking combustion turbine units to no more than 1,500 hours per year. These operating limits are in addition to proposed emission rates for nitrogen oxides, carbon monoxide, and visible emissions on peaking combustion turbines. The state of New York is proposing that new combustion turbines be required to install Best Available Control Technology (BACT) and that any other new generating source have Reasonably Available Control Technology (RACT) as a minimum. Again, the potential generating capacity reductions will lead to reduced system reliability and increased costs.

The impacts of such new acid gas legislation in Canada would be much less than in the United States due to the much lower percentage of generating capacity that is coal-fired.

The major impacts that new acid gas legislation proposals could have on utility generating capacity, particularly in the United States, has sparked an extensive research and development effort into clean coal-burning technologies. The U.S. Department of Energy's (DOE) Clean Coal Technology Program is involved with research and demonstration projects for reducing acid gas emissions from coal-fired applications. However, if tighter regulations are imposed before the late 1990s, then these new technologies and cleaner plants will not be available due to the long lead times. Unfortunately, funds for these new technologies may be diverted to upgrading existing facilities.

Maintenance of Generators — In addition to generating capacity reductions from possible tighter acid gas emissions regulations, similar reductions and reliability risks due to insufficient capacity may result from the application of current regulations to aging generating capacity. A number of power plants in the United States built prior to the Clean Air Act will require significant maintenance work to keep the units operating at acceptable performance levels. Application of current regulations to older plants undergoing major modifications, such as the five 80 MW units at the Port Washington power plant in Wisconsin, could result in premature retirement of some units or power plants if the proposed modifications are not considered routine and, therefore, come under the new source performance standards.

Some states, such as New York, are proposing legislation that will require older generating units to be retrofitted with controls to meet very low sulfur dioxide, nitrogen oxide, and particulate emission rates as well as carbon dioxide/efficiency standards. The proposed New York regulation is intended to establish a "design" lifetime of a unit at 45 years from initial operation after which time the units will be required to operate at lower sulfur dioxide, nitrogen oxide, and particulate emission rates.

Emission Caps — Utilities with total system acid gas emission limits, such as Ontario Hydro, may be forced to make large purchases from neighboring systems to meet emission cap regulations under contingency situations that may stress their own as well as other utility transmission facilities. The additional transmission to permit these environmental dispatches may also be delayed due to environmental concerns such as EMF compounding the problem and increasing the risk to system reliability.

In addition to these transmission limitations, restrictive emissions regulations in neighboring systems may limit the amount of emergency support and capacity sales even if the capacity and transmission capability are available. Systems with emission cap regulations may not be able to or may be reluctant to increase their fossil-fired generation and acid gas emissions to provide emergency assistance, economy energy, or capacity sales to neighboring systems. This will be especially true for systems that cannot trade emission credits (e.g. Canadian and U.S. neighboring systems). Utility inability or reluctance to commit to capacity sales because of emission cap regulations may effectively eliminate this important short lead-time resource option.

Operating Complexities — Due to the continuous evolution of environmental regulations, major components of the electric system, which pre-date present environmental regulations, were not designed to operate under current constraints. Restrictions on individual generating stations or total system emissions of SO_2 and NO_x and environmental dispatch instead of economic dispatch can force the system into operating modes not intended when the system was planned and designed. Such dispatch conditions may result in stressing certain transmission lines and interfaces close to their transfer limits for extended periods with increased risks to system security in the event of severe disturbances.

Emissions regulations based on not exceeding or being below some past historical levels can be very restrictive on certain types of generators. For example, oil-fired generators could be severely constrained due to regulations based on a low production year such as 1985.

These additional environmental constraints increase the difficulty of operating the electric system, increase the

stress on the operators, and thereby increase the risks to reliable customer service.

Electric and Magnetic Fields

Regulatory and judicial inquiry regarding a possible correlation between electric and magnetic fields (EMF) from power lines and health effects has resulted in the delay or cancellation of some planned transmission facilities and the removal from service of some existing facilities. Health effect concerns have surfaced in many states and provinces.

Based on laboratory and field research to date, there is no consensus among researchers that EMF due to transmission lines is harmful to human health. The evidence supporting a correlation between EMF and adverse health is weak, but because some studies have shown a possible correlation, further detailed research work is being done. Major research programs are currently underway, sponsored by a number of government organizations, utilities in Canada, the United States, and other countries, and research groups such as the Electric Power Research Institute. As the results of these studies are made public, regardless of their outcome, utilities can expect a continuing high profile and a heightened public awareness of EMF issues.

Recent Decisions — On the regulatory scene, the past year has seen a number of decisions by public service commissions and environmental review boards relating to the routing and approval of new transmission lines. For example, in 1988, the Maryland Public Service Commission reopened the certificate proceedings on a portion of the long-delayed Baltimore-Washington 500 kV loop to address claims that EMF would cause adverse health effects. The hearing was a comprehensive examination of EMF issues and found no basis to conclude that power line fields cause adverse health effects.

An example in Canada involves the application by TransAlta Utilities to construct a double circuit 240 kV transmission line in the vicinity of Edmonton, Alberta. A large part of the public hearings in November 1988 before the Alberta Energy Resources Conservation Board (ERCB) was taken up with discussion of the claimed adverse health effects of EMF. In their May 1989 decision in favor of the TransAlta proposal, the ERCB concluded there was no consensus in the evidence of the expert witnesses regarding adverse health effects of EMF. However, the ERCB did call for further research into EMF.

Two other decisions in 1989 involving EMF issues are the approval by the Colorado Public Utilities Commission of the Public Service Company of Colorado's proposal for the Daniels Park-Greenwood 230 kV transmission line upgrade and the approval by the British Columbia Utilities Commission of BC Hydro's proposal to construct the new Dunsmuir-Gold River 230 kV line.

Recently, in Berkeley Township, New Jersey, a group of local citizens attempted to prevent the initial energization of a recently completed Jersey Central Power and Light Company 230 kV transmission line, alleging adverse health effects. However, in early 1990 in the regulatory proceedings that ensued, the New Jersey Board of Public Utilities found no evidence that high voltage power lines pose a health risk to the public.

All of these decisions are supportive of the position that there is no consensus on scientific evidence of adverse health effects due to transmission line EMF. However, in each case to a varying extent, the investigation of the EMF issue increased the cost and time for obtaining approvals for the transmission line proposals. In a number of cases such as the Maryland and Colorado hearings, the decisions are being appealed. These continuing delays are increasing the risk of reduced reliability due to inadequate transmission.

Other Activities — One of the approaches being taken in the regulatory handling of EMF issues is to introduce standards. For example, in January 1989, the Florida Environmental Regulation Commission adopted emission standards for EMF generated by high-voltage transmission lines. The Florida standard for new lines is based on field levels currently found around existing lines. As a further example, New York State is considering a magnetic field guideline.

Another approach is for regulators or utilities to adopt the "prudent avoidance" policy option. For example, in November 1989, the Colorado Public Utilities Commission (CPUC) announced that it will adopt a prudent avoidance strategy to minimize EMF exposures from new power lines. The CPUC defines prudent avoidance as "taking steps to reduce exposure at reasonable or modest cost." The policy option of prudent avoidance was exercised by the CPUC in its December 1989 decision relating to the Daniels Park-Greenwood 230 kV transmission line upgrade mentioned earlier.

Utilities in several states are still facing strong opposition to the addition of required new transmission facilities. One example is in New Jersey, where the proposed Red Bank-Taylor Lane-Aberdeen 230 kV line, along an electric railway right-of-way, continues to be delayed.

A strong transmission network is essential to a reliable supply of electricity. Therefore, regulators need to proceed in an objective manner in introducing any new legislation on EMF. Possible moratoriums on new transmission line construction in response to constituents' concerns about health effects of local transmission line proposals could have severe consequences to electric supply reliability, not only in the local area but elsewhere in the state or Region. Moratoriums could cause hardships to businesses and individuals far beyond the environmental benefits, if any, which they may have.

Any regulatory action or new legislation relating to EMF effects of existing or new transmission facilities must carefully weigh the impacts on electricity costs and reliability against the perceived environmental benefits, particularly in light of the current lack of scientific consensus and understanding of this issue. The public interest will be best served through decisions and actions that are based on a cooperative approach by utilities and policymakers and on the best possible evaluation of impacts including the consequences of such decisions and actions on the electricity consumers' costs and service reliability. Some efforts have already been taken in this area in terms of jointly sponsored case studies and field tests, EMF measurements,

seminars and workshops, meetings with area residents, and preparation of videos and other information packages.

Carbon Dioxide Emissions

There is also a growing public, government, and electric utility concern regarding carbon dioxide emissions and their impact on the "greenhouse" effect or the gradual warming of the earth's atmosphere. However, there is currently no scientific consensus regarding the links between carbon dioxide emissions from burning fossil fuels, the recent droughts, and the alleged warming of the earth's atmosphere. Further, there is no consensus on whether immediate action is required, or not, and what actions would be appropriate.

As the burning of all fossil fuels, including the combustion of fuels in the transportation sector, produces carbon dioxide emissions, new regulations and strong public opposition to the use of fossil fuels could have significant impacts on electricity demand, generating capacity, and the reliability of electric supply. A total of 499,530 MW of existing fossil-fired capacity (66% of total NERC 1989 capacity) and 47,800 MW of planned utility fossil-fired capacity additions (44% of the total NERC additions over 1990-1999) could possibly be affected to some extent.

These impacts could range from unit operating limitations to premature shutdown or retirement of fossil-fired units and restrictions on the addition of new fossil-fired generating capacity. These restrictions will need to be phased in and are not expected to come into place until the end of this century or the early 2000s, beyond the time frame of this review.

There is utility concern now that very little non-fossil generation — the major non-fossil electrical generating source being nuclear energy — is capable of being approved for construction and operation to begin to replace the large amount of existing fossil-fired capacity. Climatic change could also impact the supply capability of existing thermal and hydroelectric generating capacity and transmission equipment. Switching from fossil fuels to electricity, for example, in the transportation sector could at the same time put upward pressure on electricity demand growth. All these effects have strong potential for further compounding electric supply reliability.

In light of the lack of scientific consensus on the greenhouse effect and the severe consequences on electricity demand and supply, more study is needed before public policymakers commit to any far-reaching policies in this area. It could be extremely risky and costly to prematurely enact sweeping environmental policy based on incomplete information.

Regulation and Competing Uses for Hydroelectric Capacity

Regulations requiring hydro reservoir control for environmental and recreational purposes can potentially impair operation of the 116,000 MW of existing U.S. and Canadian conventional hydroelectric generating capacity. Pressures to hold constant reservoir elevations and to maintain high dissolved oxygen levels downstream often conflict with the electric utilities' hydro requirements.

Operation of the 1,300 MW Glen Canyon hydroelectric generating plant in northern Arizona could be significantly affected by water release regulations currently in the legislative process. These proposed regulations are being promoted primarily for recreational purposes such as fishing and white water rafting. Beach erosion and boater safety are also major concerns. If the regulations are implemented, approximately 200 to 600 MW of plant peaking capability could be lost. Other hydroelectric plants along the Colorado River could also be affected by new river regulation requirements.

The 1987-89 drought has highlighted the increasing competition over the use of hydroelectric projects, and the resulting energy production losses to the utilities. River flows to the main reservoirs in the predominantly hydroelectric system in the Canadian province of Québec have been adversely affected. During 1989, Hydro-Québec experienced another dry year with below average runoff and it is expected that it will take 3 to 4 years to build the reservoirs back to normal levels.

Environmental constraints could also inhibit hydroelectric resource development. For example, although potential undeveloped small hydro resources in the Pacific Northwest are estimated to total 2,000 to 3,000 MW, environmental constraints will probably limit actual development to 400 to 500 MW. Similarly, in Ontario, about half of the undeveloped hydroelectric potential of about 12,000 MW is expected to be excluded from practical development for environmental reasons.

Reliability Issues
Fuel Supply Adequacy

An adequate supply of fuel for existing and planned generating capacity is basic to the reliability of the electric systems in NERC. Concerns about petroleum (oil and gas) fuel supply adequacy faded during the 1980s with reductions in the growth of demand for these fuels and the development of new petroleum supplies in response to the increased fuel prices during the 1970s. However, there are emerging indicators that point to uncertainties regarding the future availability and deliverability of natural gas and the availability of low sulfur residual fuel oil. In contrast, domestic supplies of coal appear to be adequate with ample reserves.

Uncertainties include the adequacy of the supply and delivery infrastructures associated with natural gas and low sulfur fuel oil and the increased use of these fuels that potential future environmental constraints on the use of coal could cause. Regulatory and logistical problems, and economic pressures involved with the maintenance of back-up fuel inventories are other reliability issues. Inability to obtain firm, long-term natural gas contracts from suppliers raises additional concerns.

Petroleum Fuels — Past and Present

The availability of reliable supplies of fuel for natural gas- and oil-fired generators has always been a major concern to electric utilities dependent on those fuels. The fuel crisis in the 1970s, symbolized by the long lines at gasoline pumps, has become a fading memory. A number of causes for the shortages of oil and gas at that time included the heavy demand for those fuels, the Arab oil embargo, and flawed regulatory policies. These shortages and the associated enormous escalation in fuel prices resulted in increased energy conservation by the public, increased exploration by domestic fuel producers, and legislation limiting the industrial and electric utility use of oil and natural gas.

In the 1970s and 1980s, electric utilities constructed baseload nuclear and coal-fired power plants to comply with legislation and to avoid the fuel supply disruptions experienced with gas- and oil-fired generators. U.S. utilities moved from generating approximately 35% of their electrical energy requirements from gas and oil in 1974 to only 14% in 1989. Coal generated electricity increased from about 45% to 54% and nuclear generated electricity from about 6% to 19% over the same period.

As a result of reduced demand and increased supplies of oil and natural gas, the early to mid-1980s saw an oil "glut" and natural gas "bubble" with a decrease in the price of these fuels and a decreased reliance on foreign oil supplies. Due in part to these decreasing prices and the lack of suitable alternatives, the late 1980s witnessed an end to the decreasing use of natural gas and fuel oil and signs of increasing use in some sectors. In addition, low prices reduced the amount of domestic exploration efforts and fuel reserve levels. The United States is now importing over 40% of the oil it is consuming compared to about 36% prior to the 1973 oil embargo.

Generating Capacity by Fuel Source

The projected electrical generating capacity in 1990 and 1999 by primary fuel type for the United States and Canada are illustrated in Figure 19. A breakdown of the capacity to be added over this same period by fuel type is shown in Table 5 of the "Generating Capacity Projections" chapter.

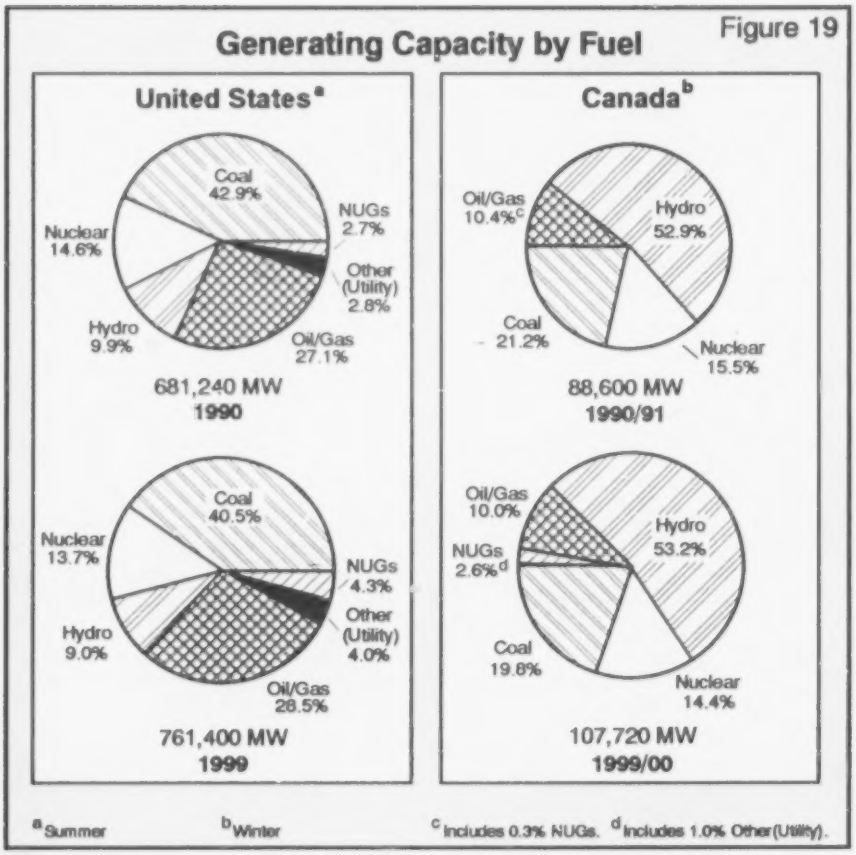
In the United States, the dominant installed generating capacity is coal-fired with gas- and/or oil-fired capacity and nuclear following. These capacity fuel types account for 85% of the U.S. total capacity in 1990. In Canada, the dominant generating capacity is hydro at 53%, followed by coal and nuclear. These three categories account for 90% of Canada's 1990 capacity.

In the United States, gas-fired, oil-fired, and NUG generating capacity is expected to increase from 30% to 33% of the total installed capacity between 1990 and 1999. About 45% of the NUG capacity additions over this period are identified as being fueled by natural gas. Coal-fired and nuclear capacity is projected to decrease from 58% to 54% of the U.S. total, although coal and nuclear capacity will increase in absolute magnitude by 21,000 MW over the 1990-1999 period.

As shown in Table 5, 55% of the capacity projected to be added in the United States between 1990 and 1999 will be gas- and/or oil-fired, or NUG capacity. The choice of gas- and oil-fired capacity additions is due to low sulfur and carbon dioxide emissions compared with coal-fired capacity, short construction lead times that provide planning flexibility, low capital costs, and the recent competitive prices of natural gas and fuel oil.

In Canada, the proportion of hydro and nuclear generating capacity over the 1990-1999 period will remain essentially the same at about 68%. There will be a slight decrease in the percentage of utility coal-, gas-, and oil-fired capacity from 31% to 30% over the same period.

The generating capacity make-up of individual Regions varies greatly. As shown in Figure 20, by 1999 coal-fired capacity ranges from 77% of the installed generating capacity in ECAR to 14% of the capacity in NPCC. Gas- and oil-fired capacity in 1999 is relied on most heavily in ERCOT (57%), SPP (48%), and NPCC-U.S. (43%). These regional differences will cause fuel supply adequacy issues to have varying im-



from 16% to 20% of the total U.S. requirements.

The fuel mix in Canada is expected to change only slightly. A small decrease is projected in the proportion of oil and gas generated electricity from 5% in 1990 to 3% in 1999. Coal, nuclear, and hydro will supply virtually the same proportions of total electrical energy requirements throughout the period.

Fuel mix statistics for electrical energy production on a national basis do not reveal regional trends or reliability concerns. Regional fuel mixes, as with generating capability, vary greatly among the Regions. Figure 22 shows the projected use of fuels for electricity production by Region for 1990 and 1999. ECAR is by far the most heavily dependent on coal with electrical energy from coal accounting for 86% of its electrical energy requirements in 1999. ERCOT will be the most dependent on natural gas with utility gas-fired units and gas-fired NUGs in 1999 accounting for 39% of its electrical energy production. Similarly, NPCC-U.S. is the area most dependent on fuel oil with 24% of its 1999 electrical energy projected to be generated by oil.

pacts on the Regions and cause different levels of concern as to their effects on electric system reliability.

Fuel Diversity

The benefits of fuel diversity were driven home to utilities in the 1970s when disruptions in the supply of natural gas and fuel oil caused serious electric supply reliability concerns, especially in the Regions that were heavily dependent on those fuels. Relying on a mix of fuels with differing characteristics of availability and delivery modes and which are affected differently by regulations and legislation provides a hedge against fuel supply disruptions.

Figure 21 shows the projected electrical energy production by fuel source from 1990 to 1999 in the United States and Canada. In the United States, electrical energy production by coal, nuclear, and hydro will drop from a total of 83% in 1990 to 79% in 1999. Gas, oil, and NUG generated electricity will increase

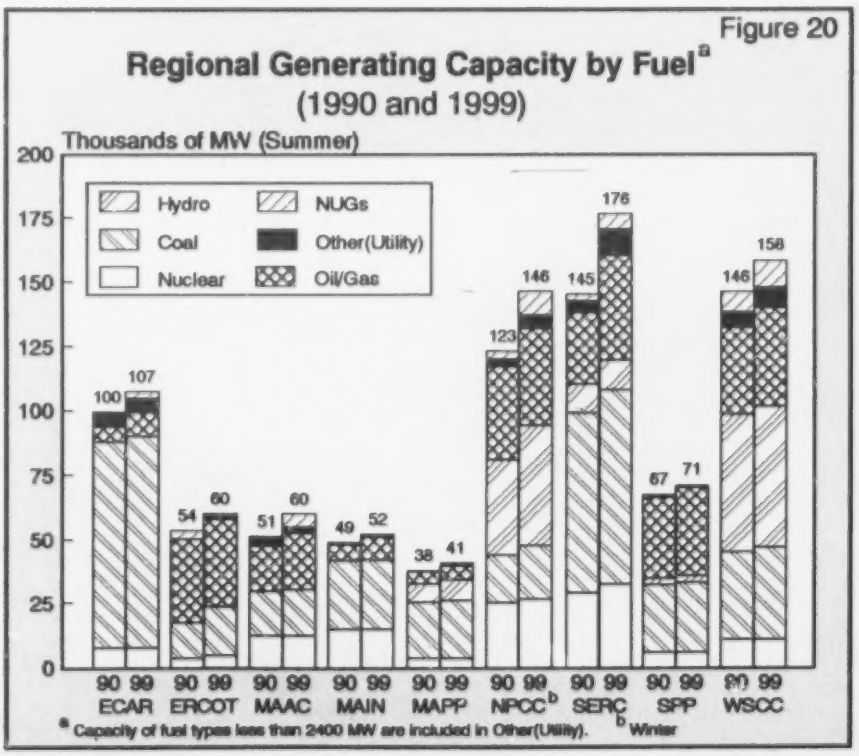
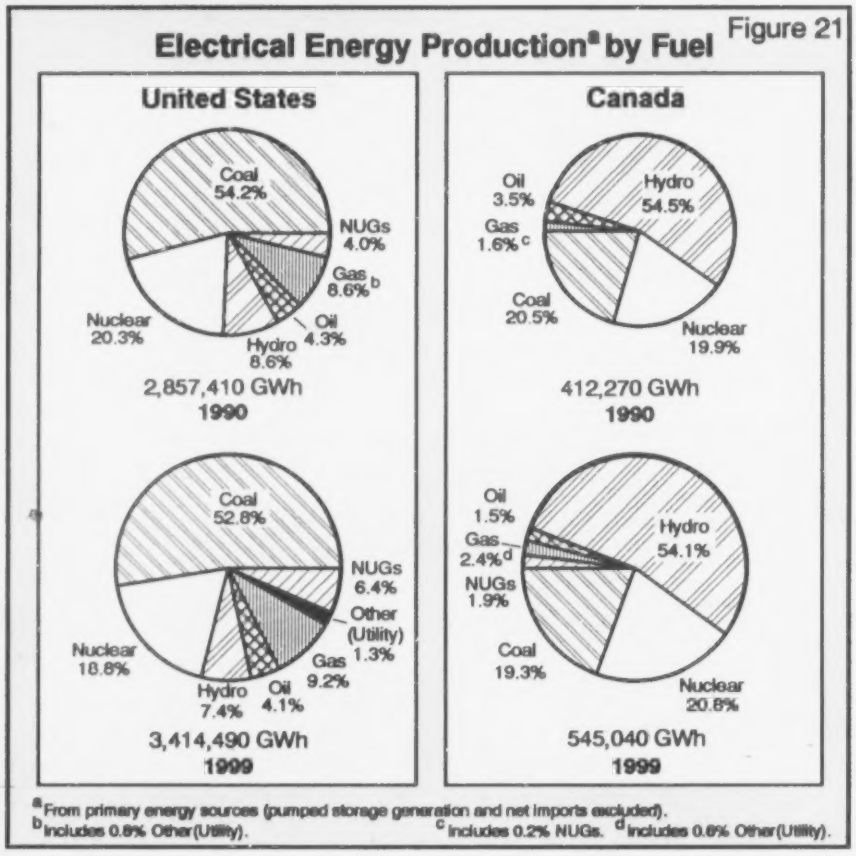


Figure 21



[a] From primary energy sources (pumped storage generation and net imports excluded).
[b] Includes 0.8% Other(Utility). [c] Includes 0.2% NUGs. [d] Includes 0.6% Other(Utility).

raises some serious questions about the future availability of natural gas. In fact, the study finds that only in limited base case scenarios does future U.S. natural gas supply meet future estimates of gas demand. It also concludes that the uncertainties associated with the more credible forecasts of natural gas supply/demand point to lower supplies or higher price. The uncertainties in the forecast of electricity demand tend to point to higher natural gas demand levels. The EEI/EPRI study makes it clear that the natural gas and electric utility industries and regulators will have to work more closely with one another to ensure that future demands for natural gas do not exceed supplies.

A major uncertainty in the demand for natural gas is the effect of proposed clean air legislation, which is discussed in more detail in the "Environmental Considerations" chapter. Such legislation could well result in replacement of coal-fired generating capacity with gas-fired capacity or the co-firing of natural gas in existing coal-fired units. The legislation, as currently contemplated, will likely put more demand on the natural gas supply than currently projected by utilities and other industries.

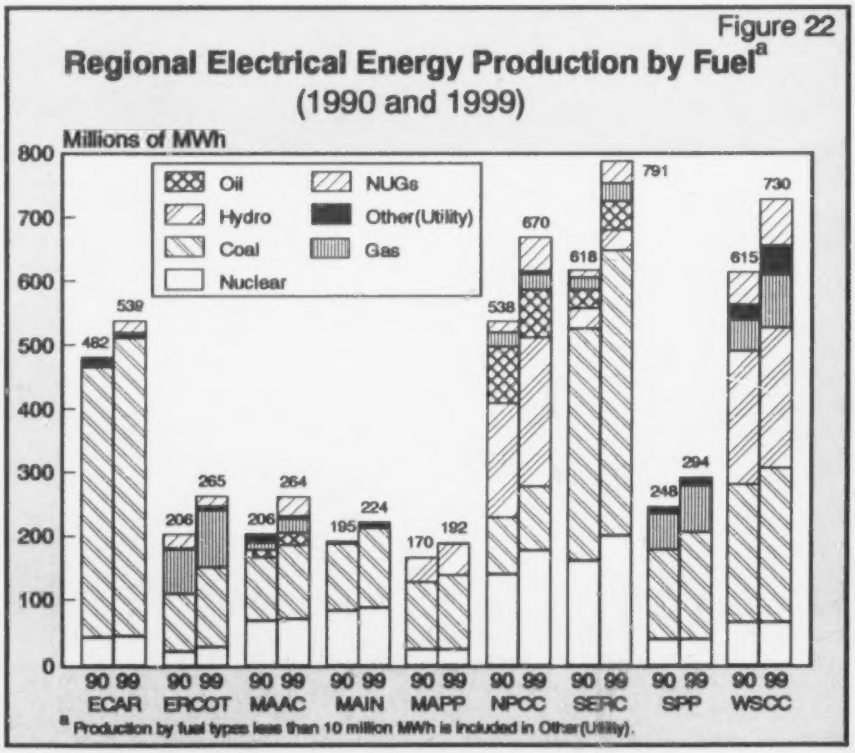
Regardless of which fuel is dominant for a particular Region, it is clear electric utilities have recognized the need for fuel diversity in their generating capacity resource plans. However, future fuel supply uncertainties could have an adverse effect on the reliability of the electric systems.

Availability of Natural Gas

The total annual consumption of natural gas in the United States was just over 18 trillion cubic feet (Tcf) in 1989. About 15% of that amount was used for the production of electricity. The use of natural gas for U.S. electricity generation is expected to increase by about 40% over the 1990-1999 period. In Canada, gas-fired generating capacity is projected to account for less than 2% of annual electrical energy production over the assessment period.

Supply — A recent study funded by the Edison Electric Institute (EEI) and the Electric Power Research Institute (EPRI)

Figure 22



[a] Production by fuel types less than 10 million MWh is included in Other(Utility).

Delivery — Limitations currently exist in the natural gas delivery system that constrain the use of gas. These limitations are likely to become more critical as the use of natural gas for electricity generation increases. Electric utilities in California experienced natural gas curtailments in November 1989 so that gas utilities could divert natural gas to storage for the winter heating season. Utilities in NPCC-U.S. routinely switch from natural gas to fuel oil in November as increasing winter demands for natural gas strain the delivery systems from the natural gas production areas in the southern and southwestern states. Even in the producing states, natural gas curtailments occur during periods of cold weather as was the case in Texas in December 1989.

Switching from natural gas to fuel oil in some cases results in derated unit capacity and operating problems. In addition, the ability to switch from gas to oil may be limited by availability and inventories as discussed below.

Availability of Oil

The United States has been importing increasing amounts of its oil requirements since the mid-1980s due to low prices and declining domestic production. This trend is expected to continue in the 1990s with the United States importing about 60% of its oil requirements by 2000.

Although oil in 1989 accounted for about 5% of the electricity generated in NERC, NPCC-U.S. relied on fuel oil for 32% of its 1989 electrical energy needs. The heavy reliance on imported oil by the United States raises a number of concerns regarding oil's future availability. These include the use of oil as a political weapon, instability in OPEC countries that control 75% of world oil reserves, and the tolerance of the United States for huge trade deficits caused mainly by oil imports.

The two major types of oil used for electricity generation are No. 6 residual fuel oil and No. 2 distillate fuel oil. Environmental constraints, as discussed in the "Environmental Considerations" chapter, will require the use of low sulfur fuel oil. Low sulfur distillate is available from domestic suppliers. However, for economic reasons, U.S. refining capacity for low sulfur residual oil is limited. Improvements in refining processes have also caused refiners to make more profitable products than No. 6 residual oil. As a result, the domestic supply of low sulfur residual fuel oil is short.

Availability of Coal

The domestic supply of coal appears to be sufficient with ample reserves. Clean air legislation is the main threat to coal use as discussed in the "Environmental Considerations" chapter. Even if such legislation allows the use of low sulfur western coal in place of higher sulfur eastern coal, this will pose problems of transportation and supply for some Regions. In addition, low sulfur coal has a lower heat content than higher sulfur coal, which will cause some capacity deratings of units that switch to the lower sulfur coal. Some boilers are also not designed to burn low sulfur coal efficiently which could cause operating problems if they are switched to such fuel.

Fuel Inventories

Most fossil-fired power plants have fuel inventories on site to insure continued operation during short-term disruptions of fuel supply. Coal plants have coal piles with several weeks fuel supply and dual fuel gas- and/or oil-fired power plants have oil storage tanks with several days capacity. Some electric utilities also have natural gas storage facilities.

The determination of appropriate levels of fuel inventory involves both reliability and economic considerations. In some states, such as Texas, regulatory authorities have placed severe limits on the amount of fuel inventories allowed in utility rate base, usually on the basis of historical consumption. However, inventories are meant to meet needs during supply disruptions that could be more severe than historical occurrences.

Some fuel oil inventories are supplied by truck. These inventories are used most often in periods of natural gas curtailment and during periods of severe cold weather. If inventory levels are insufficient, resupply during these periods may not be possible due to impassable road conditions, even if fuel oil is available from suppliers and trucks are available from shippers. In addition, the rate of use may exceed the capability of resupply, even under ideal conditions.

Fuel Supply Contracts

Provisions of utility fuel supply contracts also have an effect on uncertainties regarding fuel supply adequacy. During recent market conditions, fuel suppliers have offered very attractive short-term "spot" supply contracts. However, offsetting the low prices is a decreased commitment by the supplier to provide an uninterrupted supply. Even higher priced, long-term contracts have curtailment provisions that make them little more than "best efforts" on the sellers' part as electric utilities are usually among the lowest priority customers.

Contracts that NUGs have with their fuel suppliers also raise concerns about the NUGs' abilities to supply electricity when needed. MAAC has experienced some problems with NUGs having interruptible gas supply contracts and NUGs not being available during periods of extreme cold weather when electric demand was high and natural gas supplies were interrupted. In some cases, NUGS have dual fuel capability, but inadequate or limited fuel storage facilities raise doubts as to their availability for extended operation with alternate fuels.

Reliability Issues
Disincentives

Regulatory disallowances of utility investments from rate base have created powerful financial disincentives that can adversely impact reliability. These actions along with regulatory delays, inconsistent public policies, and overlapping jurisdictions have resulted in many electric utilities being reluctant and sometimes unable to commit to major long-term generation or transmission projects.

Competitive pressures brought on by deregulation of segments of the electric utility industry and the emphasis on short-run marginal costs are also creating uncertainties in the future reliability of electric supply.

Disincentives that discourage utilities from committing to the facilities needed to maintain adequate reliability must be addressed and removed if reliability is to be preserved.

Historical Perspective

The Federal Power Act, the Public Utility Holding Company Act, and other federal and state legislation in the United States, and provincial acts of similar import in Canada helped fashion the existing structure of the electric utility industry. The U.S. electric utilities, far from being monolithic, are comprised of hundreds of investor-owned utilities, literally thousands of publicly-owned utilities and rural electric cooperatives, and in Canada, provincial systems. All these entities, working in concert in interconnected interdependence, provide electric service with unparalleled reliability. The dependence of our society on this reliability is discussed in the "Reliability and What It Means to the Customer" chapter.

Most electric utilities operate as vertically integrated, regulated monopolies within designated geographic franchise areas under a "regulatory compact." The objectives of that regulation are to assure that:

- The electrical needs of all customers are served in a reliable and environmentally acceptable manner. Electric utilities have a legal "obligation to serve" within their designated franchise areas.

- Electric utilities are allowed to earn a reasonable rate of return on their investment to attract the capital necessary to continue to supply the needs of their customers.

In the United States, the Public Utility Regulatory Policies Act of 1978 created new classes of participants in the electric supply arena called "qualifying facilities" and "small power producers." Electric utilities inherited an "obligation to buy" from these non-utility providers under particular rates and conditions. More recently, the emergence of independent power producers (IPPs), fostered in some areas by mandatory competitive bidding programs for new generating capacity, has further complicated the planning of capacity resources.

Deregulation of segments of the electric utility industry and the unleashing of competitive forces are causing uncertainties between the electric utilities' new entrepreneurial outlook and their long-standing public service role. These uncertainties can translate into threats to reliability.

Disincentives

In the context of the electric utility industry, disincentives are circumstances or actions taken by others that tend to dissuade utilities from pursuing a course of action which they might otherwise have taken. There are numerous disincentives acting upon electric utilities today that can adversely affect reliability.

Financial Disincentives — Significant regulatory pressure is exerted on utilities to keep electric rates low. The current approach to rate setting appears to require utility shareholders to bear the risks of so-called bad investments, while denying them the incentive benefits of so-called good investments. In most cases, the characterization of the investment is determined by regulators using hindsight analysis.

Regulatory disallowances of utility investments from rate base have created powerful financial disincentives that can adversely impact reliability. Utilities are reluctant and sometimes unable to commit to a major long-term project because of the associated financial risk. Morgan Stanley and Company has estimated that approximately $13 billion of electric utility construction costs have been disallowed from rate bases over the past five years. This staggering amount of disallowance has a profound effect on how future investments are viewed by electric utilities and financial organizations.

Examples of significant financial disincentives include:

- Commonwealth Edison Company, whose earnings in 1989 did not cover dividends, recently filed for a rate increase to cover its $7.1 billion investment in three nuclear units — Byron 2, and Braidwood 1 and 2. The company has been carrying the expense for these units without any return, and has been seeking a rate increase to cover this investment for several years. These three units currently account for 21% of Commonwealth Edison's total electricity production.

- The Pennsylvania Public Utility Commission (PUC) recently denied Philadelphia Electric Company (PE) recovery of most of its investment in the Limerick 2 nuclear unit. This disallowance was based on the PUC's find-

ings of imprudency in construction costs and its assessment of PE having some 399 MW of excess capacity.

- Recent orders by the Kansas Corporation Commission cut Kansas Gas & Electric Company's (KG&E) rates and directed KG&E to refund some $8.7 million to its customers. The Commission's actions, which included penalties for previously encouraged off-system sales and disallowances of costs associated with the refueling of the Wolf Creek nuclear unit, have been characterized by the Commission's own chairman as "retroactive ratemaking."

Regulatory Delays — When the regulatory process is extended and decisions are not rendered on a timely basis, there is the risk that key facilities may not be in service when needed. Regulatory delays magnify the impact of uncertainties inherent in the planning process and increase costs.

For example, the Seabrook nuclear unit was recently granted a full operating license some four years after construction was completed. Disallowance of the recovery for construction work in progress costs drove the Public Service Company of New Hampshire into bankruptcy.

Examples of regulatory delays involving planned transmission facilities are cited in the "Transmission Reliability Assessment" chapter.

Inconsistent Public Policies — Inconsistent public policies make planning for the future reliability of electric supply extremely difficult. Utilities must be able to anticipate with reasonable certainty what the regulatory and legislative requirements will be and how they will be applied.

Consistent rulings on individual projects from initial authorization throughout the construction process and into operation are critical. Changes or inconsistently applied policies cause delays and uncertainties, lower reliability, and ultimately increase costs to electric customers.

Examples of inconsistent policies include:

- New York State's plan to dismantle the $5.5 billion Shoreham nuclear plant on Long Island is possibly the most extreme example of inconsistent public policies.

- As a result of court appeals, the Texas Public Utility Commission reconsidered the approval it granted to the Texas—New Mexico Power Company in 1986 for two 150 MW generation units. This action was taken when the first unit was complete and in commercial operation and the second unit scheduled for 1991 operation. Although the approval was upheld, the proceeding was highly contested.

Overlapping Jurisdiction — Major utility projects often require the approval of one or more federal, state or provincial, and local agencies. When the findings of these agencies conflict, unnecessary delays occur leading to the risk of inadequate system reliability.

Examples include:

- The Wisconsin Public Service Commission in promulgating rules for statewide transmission use and cost sharing agreements has raised questions regarding state versus federal jurisdiction over conditions of transmission service on the interconnected network.

- The U.S. Supreme Court has recently agreed to review a dispute between the Securities & Exchange Commission and the Federal Energy Regulatory Commission (FERC) regarding coal contracts between Ohio Power Company and a coal affiliate.

- Regulatory conflicts are also at the heart of a dispute between FERC and the Mississippi Public Service Commission regarding FERC's order reallocating investment costs of the Grand Gulf nuclear plant.

Disincentives Affect Reliability

The general reaction of electric utilities to these disincentives has been to adopt strategies to avoid large capital expenditures for major projects, especially large generating units. Most utilities have shifted toward increased reliance on short lead-time resource options. These options, which include demand management programs, capacity purchases from NUGs and other utilities, and the installation of combustion turbines, have a place in utility plans, but each has its own uncertainties.

The requirements to submit future capacity needs to competitive bidding programs can also have reliability effects due to the uncertain long-term performance of a "lowest-bidder" electric utility industry. The collective result of disjointed "least-cost" efforts may likely be a suboptimal industry-wide electric supply.

Outlook for the Future

The adequacy of resources, considering both supply and demand options, is becoming a serious concern in some areas. Now is the time to take corrective actions.

Issues that need to be addressed include:

- Recognition that the growth in electric demand is dependent on many factors outside the control of electric utilities, and that no forecasting methodology can precisely identify future requirements. The real societal costs of underestimating demand are likely to be significantly more adverse than overestimating demand.

- Recognition of the uncertainties and limitations associated with non-traditional means of satisfying customer demand — particularly non-utility generation and demand management. The long-term availability and effectiveness of these options is unknown and overdependence on such options represents an unquantified risk to future reliability.

- Recognition that a balance is needed between the competitive forces unleashed by deregulation that will tend to drive electric utilities apart and the very real need for and the economic and reliability benefits of electric utility coordination and cooperation.

- Recognition that all capacity options, including baseload units, must remain viable for flexibility in planning and responding to customer demands.

Regional Reliability Assessments

The remainder of this report assesses the reliability of the electric generation and transmission systems of the nine Regional Reliability Councils and one Affiliate member, the Alaska Systems Coordinating Council. Some key 1999 assessment information that is discussed in detail in the front portion of the report for the United States and Canada is summarized in the following table for the Regions.

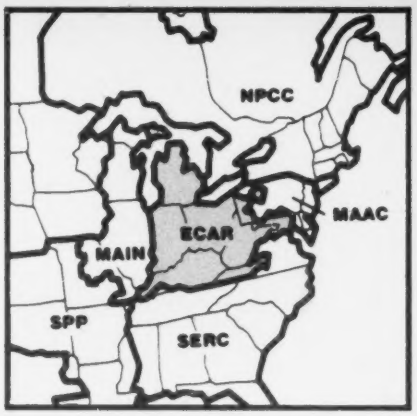
Detailed regional reliability assessments are described in the following ten chapters.

Summary of 1999 Projections for the Regional Reliability Councils

Regions	Summer Peak Demand[a] (Thousands of MW)	Annual Net Energy for Load (Millions of MWh)	Summer Generating Capability (Thousands of MW)	Summer Capacity Margin[b] (% Planned Capacity Resources)	Transmission Systems[c] (Circuit Miles in Thousands)
ECAR	91.3	515	107.5	15.1	16.3
ERCOT	52.2	267	60.2	16.1	8.0
MAAC	48.6	269	59.9	19.5	7.3
MAIN	45.4	229	52.1	15.2	5.8
MAPP	34.1	189	41.0	17.1	20.8
NPCC[d]	123.2[d]	692	146.2[d]	19.9[d]	38.5
SERC[a]	155.0	810	176.4	15.5	30.0
SPP	60.4	293	71.2	17.4	12.3
WSCC[e]	124.0	764	158.3	24.0	70.8
NERC-Total	**716**	**4,028**	**869.0**	**20.1**	**209.8**
United States	**646**	**3,476**	**761.4**	**17.8**	**160.0**
Canada[d]	**95.7[d]**	**543**	**107.7[d]**	**14.6[d]**	**49.3**
ASCC[d,f]	**0.7[d]**	**3.8**	**1.2[d]**	**43.0[d]**	**0.14**

[a]Item 3A, line 03, April 1, 1990 IE-411 reports.
[b]Capacity margin in percent is calculated by dividing the difference between planned capacity resources (Item 3A, line 13, IE-411 reports) and net internal demand (Item 3A, line 06, IE-411 reports) by planned capacity resources and multiplying by 100. Capacity margins cannot be calculated using the peak demands and generating capabilities shown in this table. Capacity margins vary from Region to Region due to variations in regional characteristics.
[c]Includes ac and dc existing and planned transmission lines operating at 230 kV and above as of December 31, 1999.
[d]NPCC, Canada, and ASCC (Alaska Railbelt electric utility systems) are winter peaking systems.
[e]Includes that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.
[f]Includes only the interconnected electric systems of the Alaska Systems Coordinating Council serving the Anchorage Bowl, the Fairbanks area, and the Kenai Peninsula and known as the Alaska Railbelt electric utility systems.

ECAR — East Central Area Reliability Coordination Agreement



The electric capacity resources planned in the ECAR Region will satisfy the ECAR criterion for adequate reliability to serve the projected demand and obligations through 1999, provided generation availability can be maintained at or above 76%. For perspective, over the last ten years, ECAR's average annual generation availability has ranged from 73% in 1980 to 80% in 1989.

Factors, such as decline in generation availability from current levels, an increase in the demand growth rate, or the impacts of compliance with pending acid rain legislation, could quickly reduce future system reliability to inadequate levels. Such conditions would limit ECAR's ability to offer emergency assistance to neighboring Regions. Conversely, as capacity reserves tighten in neighboring Regions, emergency support may not be available to ECAR, requiring that ECAR be more self-reliant. Self-reliance will make generation availability more critical, and may require installation of additional capacity resources within ECAR to maintain acceptable reliability.

The transmission network in ECAR is judged to be adequate to handle a wide range of contingencies. This judgement is based on analysis and review of transmission appraisals within ECAR and between ECAR and neighboring Regions. However, due to high levels of electricity transfers being scheduled from systems in ECAR to the east and southeast, portions of the transmission network in eastern ECAR are expected to be heavily loaded much of the time for the foreseeable future. Operating procedures have been established to control transfer levels to ensure that reliability is maintained in that part of the system. A number of ECAR member systems are participating in interregional studies under way to evaluate additional system reinforcements, such as additional voltage support, to increase the total transfer capability of that transmission interface.

Recently, two major EHV transmission system additions have been announced which, when completed, will also significantly strengthen the transmission network.

	Actual	Forecast		
Summer / Winter	1989 / 1989/90	1990 / 1990/91	1999 / 1999/00	Growth Rate (%/year)
Summer Peak – MW	75,442	78,913	91,251	1.6
Winter Peak – MW	73,080	74,455	85,756	1.6
Annual Energy – GWh	439,832	447,644	514,586	1.6
Installed Capability (Summer) – MW	97,218	99,505	107,475	0.9

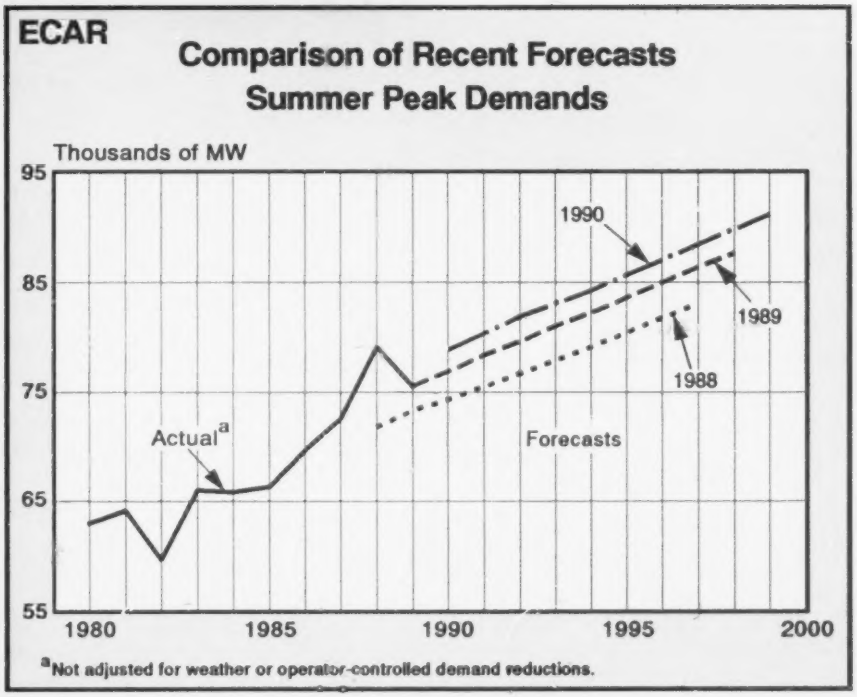
Peak Demand and Energy

Throughout the assessment period, ECAR is expected to remain summer peaking, with an equivalent compound growth rate of 1.6% per year for both summer and winter peak demands. A comparison of the years common to this year's and last year's assessment (1990-1998) shows that current summer peak demand projections are 1,900 to 2,200 MW higher this year. Similarly, current winter peak demands are from 100 to 800 MW higher. These projected changes are shown on the following forecast comparison graph.

The 1989 summer peak demand was only 0.2% below the projection, while the 1989/90 winter peak exceeded the projection by 0.9%.

ECAR's annual net energy for load has an equivalent compound growth rate of about 1.6% per year over the forecast period. This year's energy projections for the years in common with last year's assessment are 2 to 3% higher.

Coal-fired generation will continue to supply about 90% of the electrical energy produced in ECAR, and nuclear generation supplies about 9%. Such heavy reliance on coal-fired capacity will adversely impact ECAR's generation availability during the prolonged retrofitting outages of large generating units expected to be required for compliance with pending acid rain legislation. Unless such outages can be carefully coordinated among the ECAR member systems, the Region's reliability will be impaired.



Capacity Resources Adequacy

Over the assessment period, ECAR Bulk Power Members will add approximately 6,100 MW of new capacity, return about 2,100 MW to service, remove about 1,500 MW from service, and show an approximate 600 MW net capacity increase due to reratings of existing capacity. In addition, reliance on non-utility generators is projected to increase from 230 MW at the beginning of 1990 to 2,540 MW by the end of 1999. This increase includes the 1,240 MW Midland Cogeneration Venture (gas-fired combined cycle), fully in service as of July 1990.

The only large, baseload generating unit additions during the assessment period are two coal-fired units: Zimmer 1 and Trimble County 1 (totaling 1,795 MW). Both units are scheduled for service by the summer of 1991.

Construction lead time requirements are eight years or more for large, baseload coal-fired, or nuclear generating units. If the ECAR Region were to experience higher-than-projected demands or unforeseen reductions in existing capacity, it would be virtually impossible to build new baseload units for service during the ten-year assessment period. Short lead-time capacity, such as combustion turbines, might be added in time to offset capacity shortfalls. However, uncertainties in natural gas supply, site acceptability, and equipment manufacturing capability could preclude the addition of a sufficient number of combustion turbines to maintain reliability. These same factors could also adversely impact the 34 combustion turbines (totaling 3,500 MW) included in the current projected capacity additions.

Extensive probabilistic adequacy appraisals of the ECAR Bulk Power Members' generating capacity are conducted annually, considering regional peak demand patterns and generation availability. In those appraisals, ECAR's reliability is evaluated using an index called the Dependence on Supplemental Capacity Resources (DSCR), expressed in days/year. Supplemental capacity resources include assistance from neighboring Regions, dropping contractually interruptible loads, and use of direct-controlled load management. Under severe conditions, interruption of firm customers may also be necessary under emergency operating procedures. Reliability is judged against the ECAR criterion of 1 to 10 days/year DSCR providing marginal but satisfactory reliability.

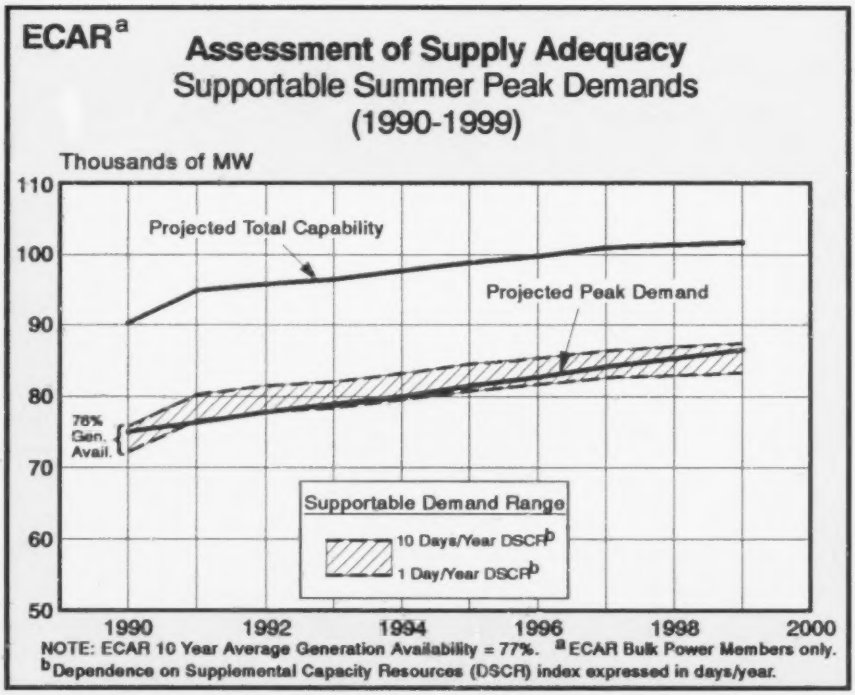
The ECAR 1990 long-term capacity appraisal determined that annual generation availability must remain about 76% for ECAR to meet its DSCR reliability criterion throughout the assessment period at the projected peak demand annual growth rate of 1.6%. Those results are illustrated on the ECAR "Assessment of Supply Adequacy" graph on the next page. That appraisal also determined that if the average annual availability declines to 75%, reliability would be inadequate by 1999. For perspective, ECAR's average annual generation availability has ranged from 73% in 1980 to 80% in 1989, averaging 77% over the ten-year period.

The availability of generating equipment is one of the most critical parameters to the adequacy of the ECAR bulk electric supply. Although high generating unit availability continues to be a goal of the systems in ECAR, it may become increasingly difficult to maintain availability at the favorable high levels experienced in recent years.

Aging generating capacity in ECAR carries the risk of decreasing availability. Normal deterioration and obsolescence will necessitate increased maintenance, and component replacements will lengthen outages. Also, should capacity margins decrease as demand grows, it may become exceedingly difficult to properly coordinate an adequate planned maintenance program, leading to an increase in random outages. Because over 30% of the capacity in ECAR will be 30 or more years old by 1999 including several of the larger units installed during the 1960s, and over 17% will be 40 or more years old, aging capacity is becoming a serious concern.

Transmission System Adequacy

The electric utility systems in ECAR have developed an extensive and reliable high voltage and extra high voltage (EHV) transmission network that is interconnected with the networks in neighboring Regions at various voltage levels. The EHV portion of the network in ECAR consists of over 2,000 miles of 765 kV, about 850 miles of 500 kV, and about 11,800 miles of 345 kV transmission. Current plans call for the addition of approximately 100 miles of 765 kV, 196 miles of 500 kV, and 87 miles of



345 kV transmission between 1990 and 1999. These planned additions are expected to enhance and strengthen the bulk transmission network.

Included in the above transmission additions are the ECAR portions of the recently announced American Electric Power Service Corporation/Virginia Power (765 kV and 500 kV) and Duquesne Light Company/General Public Utilities (500 kV) transmission projects. Those projects were not included in ECAR's 1990 IE-411 report because they were announced after that report was filed with the U.S. Department of Energy.

In recent years, fuel cost differentials have fostered large, short-term, economy energy transfers, in addition to long-term capacity and energy transfers. Significant intraregional and interregional energy transfers are routinely arranged on daily and hourly bases. These transfers have caused power flow patterns on the transmission systems that were not anticipated when the transmission systems were originally planned. Therefore, the transfers must be carefully monitored and controlled to assure reliable operation of the interconnected transmission systems in ECAR.

To properly coordinate the planning and operation of the interconnected systems, seasonal transmission performance studies are conducted in ECAR, and jointly with all neighboring Regions, prior to each summer and winter peak demand period. The transmission systems are also regularly analyzed for future periods of interest.

In general, these studies indicate that the ECAR bulk transmission systems should perform adequately under a wide range of credible system conditions. However, portions of the transmission systems in eastern ECAR are expected to be heavily loaded much of the time due to large interregional transfers. A set of operating procedures, called the Reliability Coordination Plan (RCP), was developed by the utilities owning and operating the transmission systems in eastern ECAR, the MAAC Region, and the VACAR subregion of SERC. The RCP is used to control transfers to ensure that reliability is maintained in that heavily loaded part of the transmission network. A number of ECAR member systems are participating in interregional planning studies that are evaluating system reinforcement alternatives, including additional voltage support, to increase the total transfer capability on that interregional transmission interface.

Impact of Proposed Acid Rain Legislation

Coal, the predominant fuel used within the ECAR Region, is expected to supply about 90% of the total electrical energy requirements during the assessment period. Therefore, the potential reliability impacts of compliance with currently proposed acid rain legislation could be serious for some systems in ECAR.

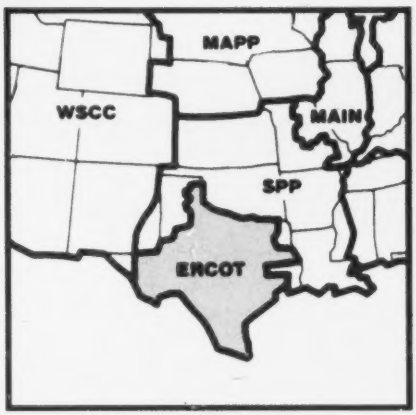
To assess these reliability impacts, a survey was conducted as part of the 1990 ECAR long-term appraisal. The survey was based on the U.S. Senate version of the Clean Air Act (S. 1630). Each system in ECAR was requested to identify the effects of this legislation based on their current thoughts for achieving both the Phase I and Phase II limits, and to provide an estimate of the reliability impacts, i.e., any change in unit rating and/or availability of generating equipment on a unit-by-unit basis. The data provided by the member systems are subject to change once the final legislation is enacted, and rules and regulations have been developed.

Preliminary results of the survey indicate that about one-half (50,000 MW) of the ECAR Bulk Power Member's capacity will be impacted in some manner by compliance with the Phase I and II limits. Capacity retirements and derates are expected to total approximately 1,550 MW. Adverse reliability impacts are also expected due to projected increases in random outage and maintenance factors.

The emissions cap provisions of the legislation may lead to environmental constraints taking precedence over economic dispatch in generation control. Should a utility be at or approaching its emissions cap, it may be unable to provide emergency assistance to a neighboring utility without exceeding its cap.

The East Central Area Reliability Coordination Agreement (ECAR) Region bulk power membership currently consists of 28 companies (19 systems) serving either all or part of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland, and Tennessee.

ERCOT — Electric Reliability Council of Texas



ERCOT is expected to have adequate capacity margins for the forecast period based on current capacity and demand forecasts. Capacity margins range from 24.1% in 1990 to 15.5% in 1998. Peak demand and electrical energy forecasts show slight increases in growth rate from the previous forecasts with the annual growth rate for summer peak demand increasing from 2.2% to 2.5% and annual energy from 2.4% to 2.9%. Delays in the addition of needed transmission lines and natural gas supply disruptions are the major concerns for electric system reliability in the Region.

	Actual	Forecast		
Summer / Winter	1989 / 1989/90	1990 / 1990/91	1999 / 1999/00	Growth Rate (%/year)
Summer Peak – MW	40,402	41,880	52,171	2.5
Winter Peak – MW	38,388	34,059	44,444	3.0
Annual Energy – GWh	207,304	205,819	266,642	2.9
Installed Capability (Summer) – MW	51,927	53,560	60,187	1.3

Peak Demand and Energy

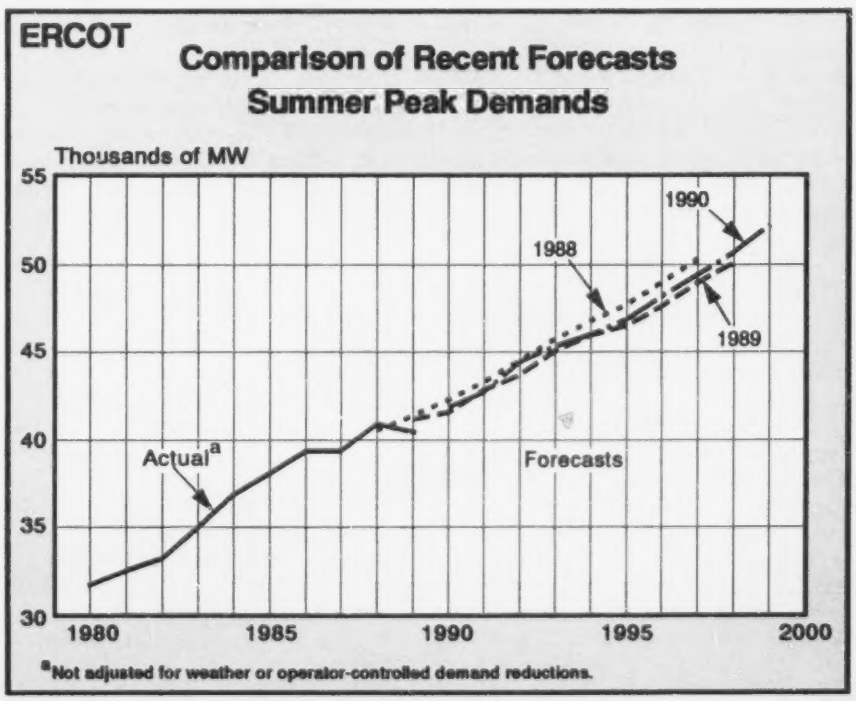
The 1989 actual summer peak demand in ERCOT was below the forecast of 41,169 MW by 1.9% primarily due to cooler than normal temperatures. It was also below the 1988 actual peak of 40,843 MW by 1.1%.

The average annual growth rate in summer peak demand forecasted by ERCOT utilities over the period 1990-1999 is 2.5%, a slight increase from the 2.2% growth rate projected last year. The projected summer peak for 1998, the last common year of both forecasts, is up 603 MW or 1.2% from last year's forecast.

Although ERCOT is expected to remain a summer peaking Region, the growth rate of winter peak demands is forecasted to exceed that of summer peaks. Two utilities in ERCOT have experienced and now project their peak demands to occur in winter due to a high concentration of electric heating in their service areas.

Utility-controlled load management programs, including interruptible demands, are projected to range from 1,434 MW or 3.4% of the 1991 summer peak demand to 1,665 MW or 3.2% of the 1999 peak.

Average annual electrical energy growth for the 1990-1999 period is projected to be 2.9%. This is an increase from last year's forecast of a 2.4% annual increase, largely due to more optimistic projections of economic growth in the Region.



Capacity Resources Adequacy

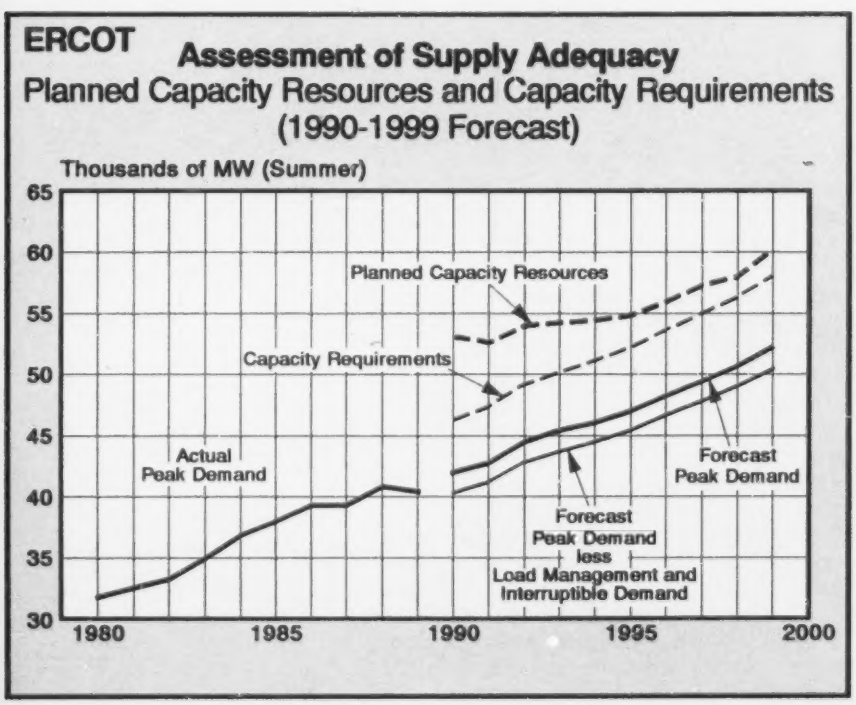
The capacity margin in ERCOT is expected to range from a high of 24.1% in 1990 to a low of 15.5% in 1998. Projected capacity margins for the 1990-1999 period are expected to be adequate, exceeding the minimum planning guidelines adopted by the Region. Currently projected installed generating capacity could support an annual average 2.9% growth in summer peak demand, compared to the 2.5% currently forecasted, while still meeting minimum ERCOT Planning Criteria. A comparison of ERCOT's planned capacity resources and capacity requirements over the forecast period is shown in the following figure.

Utility generating capacity increased by 1,106 MW in 1989. Additional utility generating capacity scheduled for installation between 1990 and 1999 totals 10,728 MW. This includes 4,830 MW of coal capacity, 2,300 MW of nuclear capacity, and 3,598 of combustion turbine and combined cycle capacity. An additional 2,500 MW of currently unspecified capacity is also projected to be added during the period. Retirements and shutdowns of existing gas-fired units are expected to remove 1,084 MW of capacity from service during the period. Capacity obtained from non-utility generators is projected to decrease by 2,445 MW. This results in a total net capacity increase in the Region of 9,699 MW.

Non-utility generators, which are mainly gas-fired cogenerators, are projected to account for 2,972 MW or 5.6% of summer capacity resources in 1990 and 824 MW or 1.4% of summer capacity resources in 1999. This decrease in NUG capacity is due to contract expirations, and the capacity may continue to be available under future contractual arrangements. The minimum summer capacity margin of 15.5% in 1998 would be reduced to 13.6% without non-utility generator capacity.

The third of the Region's four nuclear units, Comanche Peak 1, went into commercial operation in August of 1990. The fourth unit, Comanche Peak 2, is scheduled for commercial operation before the 1993 summer peak season.

ERCOT will remain heavily dependent on natural gas-fired capacity throughout the period. ERCOT is expected to depend on utility gas-fired generation for 34% of its electrical energy requirements in 1990 and 33.6% in 1999. Electrical energy supplied by natural gas-fired non-utility generators will add 5.5 percentage points to the utility gas-fired generation in 1999 for a total of 39.1%.



Transmission Adequacy

The backbone of the ERCOT bulk electric transmission system is its 6,886 circuit mile 345 kV transmission network. ERCOT members expect to add 1,120 circuit miles of 345 kV lines in the next ten years. This is a 4% increase from the ten-year projection made in 1989.

A proposed 600 MW East DC Tie to be jointly owned by utilities in ERCOT and the Southwest Power Pool has received approval from the Federal Energy Regulatory Commission. This project, currently projected to be completed by 1995, will increase the transfer capability between ERCOT and the Southwest Power Pool to approximately 800 MW.

The construction of the 345 kV Salem-Zenith interconnection between Houston Lighting & Power Company (HL&P) and the Lower Colorado River Authority (LCRA) continues to be delayed by the Texas Public Utility Commission's (PUC) rejection of a 1986 application for construction and subsequent litigation. The application was remanded by a State District Court to the PUC. An appellate court confirmed the District Court ruling, but that action was appealed to the State Supreme Court. The State Supreme Court heard arguments on the case in December 1989 and in September 1990 returned the case to the lower court for a detailed evidentiary review.

Another transmission project that will not be in service as originally scheduled is a 345 kV transmission tie between HL&P, LCRA, and the Texas Utilities Electric Company. This line is associated with the Salem-Zenith transmission line and will likely be delayed until that line is approved.

An application for construction of a 345 kV line between Central Power and Light Company's Coleto Creek and Lon Hill power plants has been filed with the PUC. This major transmission project is critical to the reliability of several ERCOT members in South Texas. Approval of the project by the PUC is uncertain since several parties opposing the

project have been granted intervenor status in the proceeding.

Studies have shown that the bulk electric systems as planned should meet ERCOT reliability criteria through 1999. However, significant uncertainty is associated with completion of some of the major transmission projects as previously discussed. These uncertainties could pose a threat to electric system reliability in ERCOT.

Operations

Capacity transfers of various types among utilities and from remote non-utility generators continue to utilize the ERCOT transmission network. In 1989, 1,327 MW of firm capacity from non-utility generators and 367 MW of firm transfers among utilities were wheeled over the transmission systems. In addition, 3,039 GWh of economy energy transfers occurred among ERCOT utilities in 1989. These uses of the ERCOT transmission network have benefitted ERCOT customers by minimizing electricity production costs.

On December 23, 1989, during some of the coldest weather to ever occur in Texas, ERCOT was forced to implement Region-wide firm customer load shedding for the first time in its history. Weather related outages of generating units and high customer demand caused capacity shortages that threatened the stable operation of the interconnected system. The ERCOT Security Centers called for the shedding of 500 MW of firm customer demand in the ERCOT system. This action allowed the interconnected system to stabilize and recover within a few minutes. Most affected customers experienced a loss of electric service for less than an hour.

Natural gas supplies were curtailed to most electric utility generators during the December 22-23, 1989 cold weather period. Units that had dual fuel burning capability were converted to fuel oil during this period.

Issues Influencing Reliability

The major reliability issues of current concern to ERCOT member systems are:

- Natural Gas Supply — In 1990, natural gas is expected to provide 44% of ERCOT's electrical energy requirements from both utility and non-utility generators. Although the percentage of total electrical energy production obtained from natural gas will decrease to 39.1% in 1999, ERCOT's use of natural gas will increase 14.6% from 1990 to 1999. This continued heavy dependence on natural gas causes the availability of natural gas supplies to be a reliability concern.

  Current gas supplies are abundant and prices are attractive. Nevertheless, ERCOT utilities experience curtailments of their gas supplies during periods of cold weather so those supplies can be diverted to meet high residential heating demands. Reduced drilling activity for new natural gas supplies and the likely increased demand nationally for natural gas due to its environmental advantages cause concern that the availability of natural gas for electricity generation will decrease in the future.

- Fuel Oil Inventories — To maintain electrical generation during periods of natural gas curtailments, ERCOT member utilities store fuel oil to use as a backup fuel source. Economic and regulatory pressures exist to keep these fuel oil inventories low. There is concern in ERCOT that current inventories may not be sufficient to maintain electric system reliability for an extended period of natural gas curtailments.

- Construction of Transmission — It is becoming increasingly difficult for ERCOT member utilities to obtain the necessary approvals to construct needed transmission facilities. This comes at a time when the ERCOT transmission network is increasingly utilized for both firm and economy interchanges.

  Needed interconnections between utilities, such as the Salem-Zenith 345 kV transmission line, along with internal transmission improvements necessary for local service reliability have been delayed several years past their originally scheduled in-service dates due to regulatory and legal impediments. These delays cause increased loadings on the existing transmission systems that can limit capacity transfers among utilities.

- Questions on the Effects of Electric and Magnetic Fields — One of the issues cited in regulatory and legal proceedings concerning transmission projects is alleged health effects of electric and magnetic fields. There are also questions as to whether this issue will affect the operation of existing facilities. A special task force appointed by the Texas PUC is scheduled to report on EMF effects this year. This issue could affect the future reliability of the ERCOT system.

The Electric Reliability Council of Texas (ERCOT) is comprised of 26 municipalities, 52 cooperatives, six investor-owned utilities, and two state agencies, which serve a total of 11 million customers. These systems operate 85% of the electric generation in Texas and serve approximately 200,000 square miles or 75% of the area in the state.

MAAC — Mid-Atlantic Area Council

The MAAC Region's operating reliability has at times over the past two years been below desired levels due mainly to constraints on the interconnected transmission systems. MAAC and adjacent systems are constructing short lead-time transmission enhancements that will improve the overall performance of the transmission network. Once these enhancements are in place, MAAC projects adequate generating capacity and transmission resources throughout the remainder of the 1990s.

Following the completion of the 640 MW Brandon Shores coal-fired unit in 1991, MAAC will rely upon short lead-time resource options to closely tailor its resources to need for the remainder of the decade. As a result, there is not much leeway for variation in the planning assumptions. If peak demand grows faster than forecast, or if non-utility generator additions or projections of demand management impacts do not materialize, MAAC will be faced with a need to adjust its plans by adding increased amounts of short lead-time generating capacity.

Other reliability enhancing measures slated for the 1990s include installation of a fourth 500 kV interconnection with ECAR, completion of the long delayed Baltimore-Washington 500 kV loop, the upgrading of the PJM Interconnection Office system security analysis capability, and participation in the Inter-utility Data Exchange.

Actual		Forecast		
Summer	1989	1990	1999	Growth Rate
Winter	1989/90	1990/91	1999/00	(%/year)
Summer Peak – MW	41,614	42,735	48,624	1.4
Winter Peak – MW	38,161	37,825	45,423	2.1
Annual Energy – GWh	223,922	224,159	268,956	2.0
Installed Capability (Summer) – MW	49,829	51,194	59,859	1.8

Peak Demand and Energy

For the first time in the last seven years, the summer of 1989 did not provide MAAC with a new all-time record peak demand. This was mainly the result of near normal weather conditions during the 1989 summer, while the prior two summers had featured temperatures that were significantly warmer than normal. The actual 1989 summer peak of 41,614 MW was 3.5% below the 1988 summer peak, and only 0.1% above forecast. No emergency operating procedures were in effect at time of system peak. Net annual electrical energy for the MAAC system in 1989 increased 2.4% over 1988.

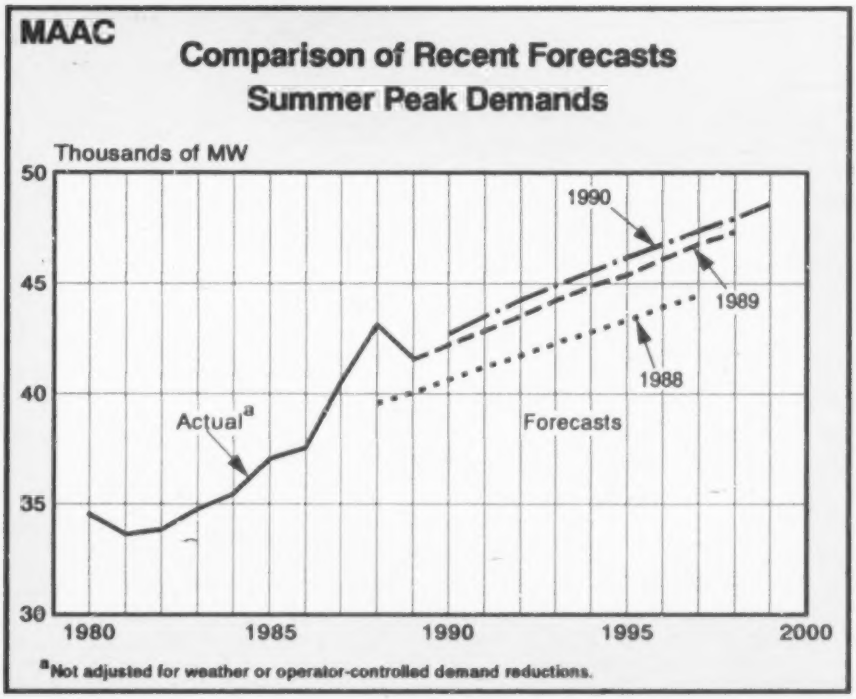
MAAC summer peak demands are expected to grow 1.4% per year to 48,624 MW in 1999. Growth in annual electrical energy is projected to be 2% per year over the forecast period.

Although load management was not prominent during the 1989 summer peak day and no emergency operating procedures were in effect, load management and emergency procedures did have a significant impact on reducing peak demands when needed. System demand was reduced up to 2,000 MW by load management and emergency procedures during other high peak demand days in 1989. The load management portion of MAAC's overall demand management programs is forecast to grow about 1,000 MW between 1990 and 1999.

Capacity Resources Adequacy

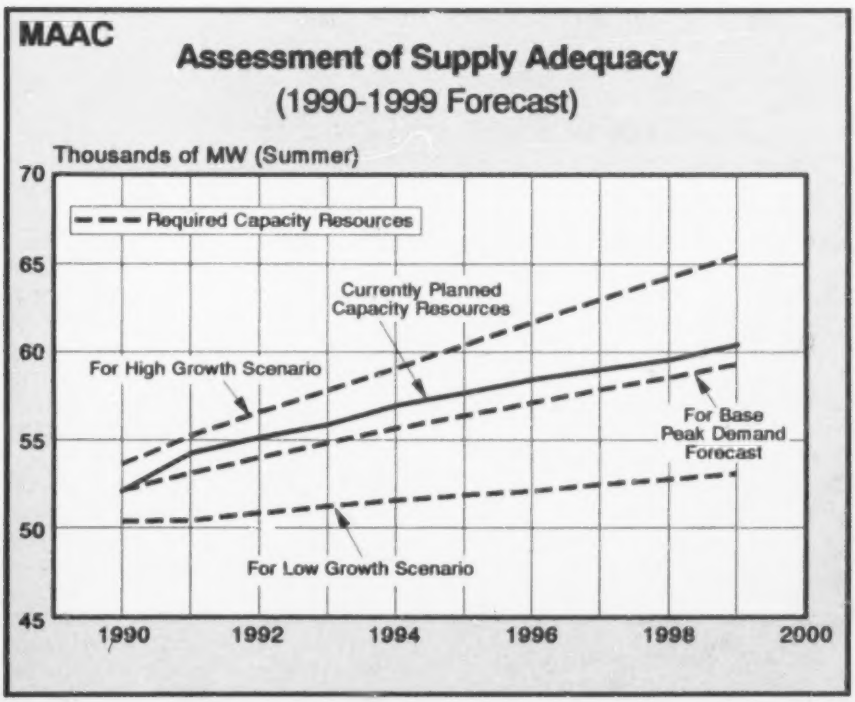
Installed generating capacity in MAAC is expected to increase by about 8,665 MW between 1990 and 1999. Conventional utility baseload capacity comprises about 9% of the new resources, most of which is represented by the 640 MW Brandon Shores 2 coal-fired unit scheduled for commercial operation in 1991. The remaining new capacity resources are comprised of 5,045 MW of short lead-time utility generation, such as oil- or gas-fired combustion turbines and combined cycle units, and 3,608 MW of non-utility generators. This capacity will be required to supply peak demand growth given expected retirements of older utility plants and the reduction of capacity purchases from other Regions.

During 1989, the Limerick 2 nuclear unit, 1,055 MW, became commercial, improving MAAC's capacity resources in the near term. Limerick 2 represents the



last nuclear unit in MAAC's ten-year forecast — there are no others either currently planned or under construction.

A comparison of net MAAC planned capacity resources and capacity resources required for various peak demand projections is illustrated in the figure below. The figure shows that planned available capacity operating margins will continue to be tight, and if peak demand grows faster than forecast, MAAC utilities may have to install additional short lead-time generating capacity. This action might also be required if some planned non-utility generators do not materialize, or if planned increases in load management programs fail to produce expected peak demand reductions.



MAAC utilities' attempts to meet future requirements by purchasing capacity from other Regions have been only moderately successful. State regulatory agencies have discouraged such arrangements in an effort to stimulate growth in non-utility generator alternatives and increased load management initiatives.

MAAC utilities have been successful in reducing generator unit unplanned outages through intensified maintenance practices. Such programs have significantly reduced unplanned unit outages in the last few years.

In recent years, MAAC has experienced lengthy outages beyond normal refueling cycles for one or more of its 13 nuclear units. The year 1989 was no exception as five of MAAC's nuclear units experienced unplanned, extended outages throughout all or part of the summer, adversely affecting reliability. The nuclear operating utilities within MAAC are making every effort to reverse this trend.

Transmission Adequacy

MAAC utilities plan to add an additional 267 miles of 500 kV transmission and 460 miles of 230 kV transmission by 1999. Major 500 kV developments include the newly announced interconnection between General Public Utilities (GPU) in MAAC and Duquesne Light Company in ECAR scheduled for 1996, the completion of the Baltimore-Washington 500 kV loop, and the alternate "Seashore loop" in New Jersey.

The Baltimore-Washington 500 kV loop is required to provide adequate interregional transfer capability near MAAC's southern and western interfaces and to provide adequate stability margins in the Baltimore-Washington area. After many years of delay involving siting and certification, and related court actions, this vital reinforcement recently cleared the last remaining obstacle to completion. Such open-ended approval and

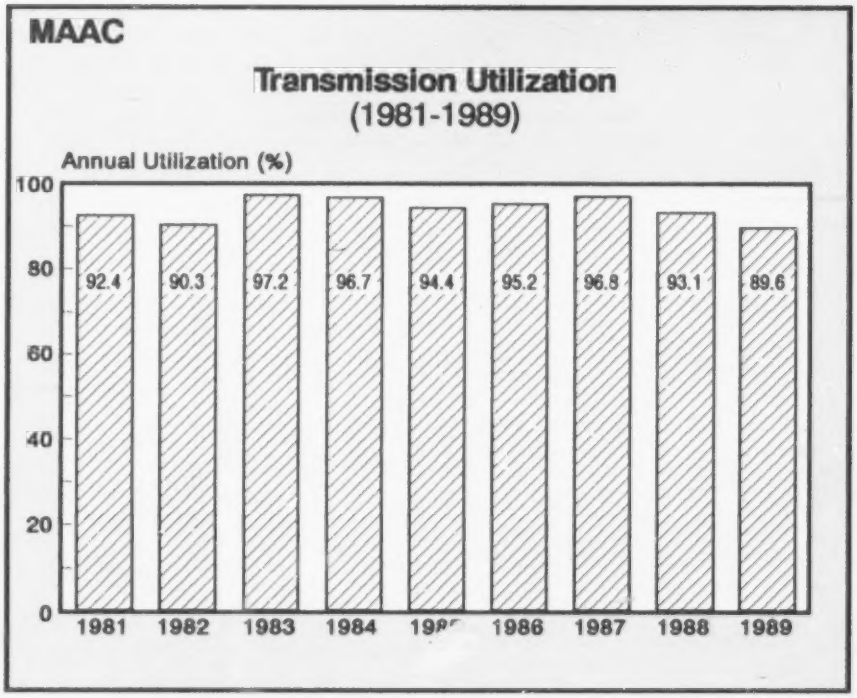
judicial review processes represent a threat to the timely completion of other planned transmission facilities necessary to supply customer demand, particularly, in the high growth areas within MAAC.

Reliability of supply in the MAAC Region and adjacent Regions is dependent upon adequate transfer capability among these areas. MAAC plans its transmission network with sufficient emergency import capability to maintain reliability of supply. Two specific threats to MAAC's ability to receive emergency assistance in the future include a current threat and a longer-term threat.

The current threat is the limitation to the capacity of the transmission network in the area of MAAC's interface with the ECAR and SERC Regions. Coordinated interregional studies are under way to develop plans for transmission enhancements that will eliminate the transmission bottlenecks. As a result of the first phase of these coordinated studies, MAAC and the Allegheny Power System in ECAR plan to install about 1,800 megavars of shunt capacitors in the 1991-92 time frame that will achieve short-term improvements in MAAC's ability to obtain emergency assistance. In addition, the GPU/Duquense 500 kV line is expected to enhance MAAC reliability by improving MAAC's transmission capability from systems to the west.

The second or long-term threat to MAAC's emergency assistance from adjacent Regions is the increasing uncertainty that capacity will be available in these Regions when needed by MAAC. Current generating capacity forecasts indicate a steady decline of capacity margins throughout the NERC Regions, particularly in the eastern United States. In the longer term, emergency assistance may be limited by available generating capacity in adjacent systems rather than by transmission capability.

To assure that its system planning studies are properly defining and developing the transmission network to maintain reliability, MAAC has undertaken two recent initiatives. The first is a review and update of its criteria for system planning. The second is a reassessment of its emergency capacity import capability, and the study assumptions and methodology used to analyze these transmission needs.



Solar magnetic disturbances affected MAAC and other Regions in the Northeast in March of 1989. Geomagnetic-induced currents damaged generator unit step-up transformers at the Salem and Hope Creek nuclear generating stations. MAAC is conducting a study to determine which system components are vulnerable to misoperation or damage, and to develop operating procedures and alternative designs to protect equipment that may be at risk. An operating procedure has already been put into place to reduce the risk of future solar magnetic induced damage to the Salem and Hope Creek generator step-up transformers.

Operations

Economy interchange of capacity within MAAC, economy imports from systems west of MAAC, and unscheduled flows due to transactions among neighboring systems all contribute to heavy west-to-east loadings on the MAAC transmission network. These effects result in high utilization of portions of MAAC's transmission network as illustrated in the above bar chart. Although planning studies indicate a slight lessening of west-to-east transmission loadings over the next ten years, heavy flows will continue to prevail and the voltage constraints that result will continue to be the focus of operator attention.

The combined impact of MAAC's imports from the west and the transactions of other utilities in the ECAR, SERC, and NPCC Regions have contributed to voltage limits on the transmission network at the ECAR-SERC-MAAC interface. The Reliability Coordination Plan, jointly developed and implemented by systems within these three Regions, is a coordinated approach to monitoring and controlling the voltage problems in this area by controlling the transactions that cause them.

Several independent activities in progress at MAAC's control center will enhance the coordinated control and operation of the MAAC system. First, the control center's energy management system is being upgraded to provide advanced security functions that will assist operators with improved real-time monitoring and analysis capabilities. Second, MAAC's control center is involved with personnel from adjacent pools in a project to improve operation of the intercon-

nected electric systems through the planned mutual exchange of real-time system data.

Finally, mid-term operating studies are now being conducted in MAAC to explore expected operating problems for the next one to two years — a time frame that will permit short lead-time actions to improve reliable operations.

Reliability Issues

Although the planned MAAC system provides adequate future supply for forecast demand conditions, several factors threaten this balance between demand and supply capability. Key risk factors include:

- Higher Than Forecast Demand — While planned capacity is sufficient to provide adequate electric supply to meet forecast peak demand projections (1.4% annual growth), relatively minor increases in peak demand growth can pressure MAAC utilities to quickly bring additional new capacity sources on line. For example, a 2.2% annual growth rate would necessitate 5,100 MW of additional generating capacity by 1999. The capacity options to respond to such increased demand are limited — primarily short lead-time oil- and gas-fired capacity.

  Since the conditions that would trigger peak demand forecast increases would probably be more widespread (national) in scope, other Regions would likely be placing orders for new short lead-time capacity as well. The ability of the manufacturing sector to respond to this demand for equipment is in question.

  Further, even if this equipment could be built in time, the ability of the MAAC utilities to bring these units online when needed would be made difficult by the existing regulatory and environmental licensing and permit processes.

  Finally, this short lead-time capacity would be subject to the uncertainties of available supplies of fuel oil and natural gas.

- Emergency Import Capability — As with other Regions, MAAC utilizes its transmission ties to provide various types of economy and emergency interchanges. The recent growth in such transactions has resulted in heavy loadings of the transmission systems in and around MAAC. MAAC and a few of its neighboring systems are conducting studies to develop short-term and longer-term transmission reinforcements that will assure desired levels of emergency transfer capability.

  By the end of the ten-year forecast period and beyond, published generating capacity forecasts for Regions in the Eastern Interconnection indicate a broad decline in capacity margins. This trend raises concern as to whether emergency capacity assistance will be available in the future, whether or not the transmission network capacity is adequate.

  MAAC utilities are also concerned about the prospects for being able to build needed transmission in a timely manner, if at all, given the current environmental climate and lengthy review and approvals processes. The delay of the Baltimore-Washington 500 kV loop is a dramatic example of the difficulty in building needed transmission. This interregional transmission reinforcement is vitally needed to improve transfer capability among the MAAC, ECAR, and SERC Regions and to supply the Baltimore and Washington, D.C. areas.

  Mounting public concern over the effects of electric and magnetic fields has recently served to further prolong the review process related to specific planned transmission projects, particularly in New Jersey.

- Availability of Existing Generators — It is important that existing capacity be kept available, especially at times of system peak to maintain supply adequacy in MAAC.

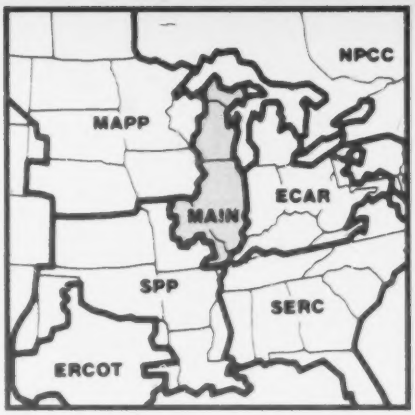
  Nuclear unit availability in MAAC has not been as good as expected, as these units have been vulnerable to extended outages. Companies operating nuclear units must make every effort to assure that the highest standards of safety and performance are maintained at these plants, as these large units play a critical role in assuring adequate electric supply in the MAAC Region.

  The disruption of fuel oil and natural gas supplies poses a threat to a significant portion of MAAC's generating units that rely on these fuels. The growth of non-utility generators, many of which are fueled by natural gas, and some of which are associated with interruptible gas supply contracts, heightens this concern.

  Environmental legislation that might adversely affect the availability and capacity of existing coal-fired generators is another factor that can reduce the reliability of existing capacity resources.

The MAAC Region consists of 11 member systems and five associates serving over 20 million people in a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small portion of Virginia.

MAIN — Mid-America Interconnected Network



MAIN plans to provide adequate generating capacity on a continuing basis. However, probability studies indicate that considering demand forecast error and uncertainties due to weather, MAIN may have to add additional resources as early as 1996. Consequently, MAIN is already investigating the effectiveness of various strategies to assure adequate reliability.

The major reliability concern is the unknown effects on future generating capability of regulatory actions related to acid rain. Additional concerns are supply adequacy should peak demand exceed projection, and the application of air quality standards to fossil plant maintenance projects.

The transmission network in MAIN is adequate for reliable operations for both internal transfers and those involving adjoining Regions.

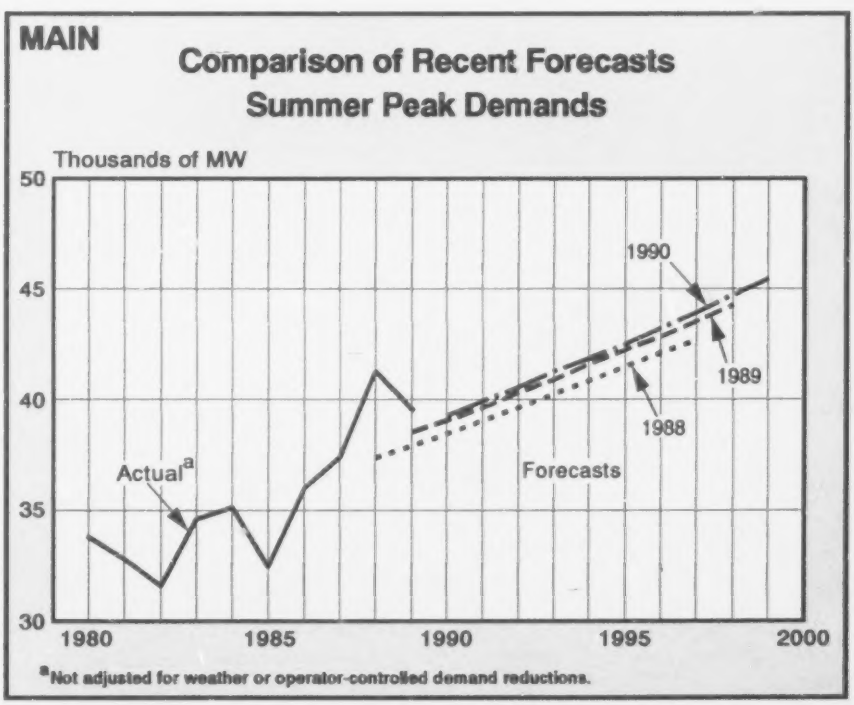
	Actual		Forecast		
	Summer	1989	1990	1999	Growth Rate
	Winter	1989/90	1990/91	1999/00	(%/year)
Summer Peak – MW		39,460	39,191	45,438	1.7
Winter Peak – MW		33,770	32,117	37,761	1.8
Annual Energy – GWh		194,535	195,145	229,193	1.8
Installed Capability (Summer) – MW		49,373	49,182	52,145	0.7

Peak Demand and Energy

The 1989 summer peak demand for MAIN was 1,679 MW less than the 1988 peak demand of 41,139 MW, which was the all-time high. The actual 1989 peak demand was 1,045 MW or 2.7% above forecast. Both actual and weather-corrected peak demands have exceeded forecasts for the past four years.

The MAIN 1989 summer peak demand was reduced about 22 MW by removal of contractually interruptible customer demand. No voltage reductions or emergency operating measures were used during peak demand periods in the past year.

Actual peak demands and a comparison of recent peak demand projections are shown in the adjacent figure. Summer peak demand for the 1990-1999 period is forecast to increase at an average annual rate of 1.7%, the same rate forecast last year. The current forecast shows some change from last year's



forecast for specific future years. For example, the present forecast for 1998 summer peak demand is 489 MW or 1.1% higher than that made last year for 1998.

Actual 1989 annual electrical energy requirements in MAIN were slightly higher than in 1988, and 2% above forecast.

Capacity Resources Adequacy

Generating capacity in MAIN is and will continue to be about 54% coal and 30% nuclear throughout the forecast period. In 1990, 54% of the electrical energy generated in MAIN will be from coal and 44.5% from nuclear. In 1999, expectations are that coal will supply 55.6% and nuclear 40.7% of the electrical energy generated in MAIN.

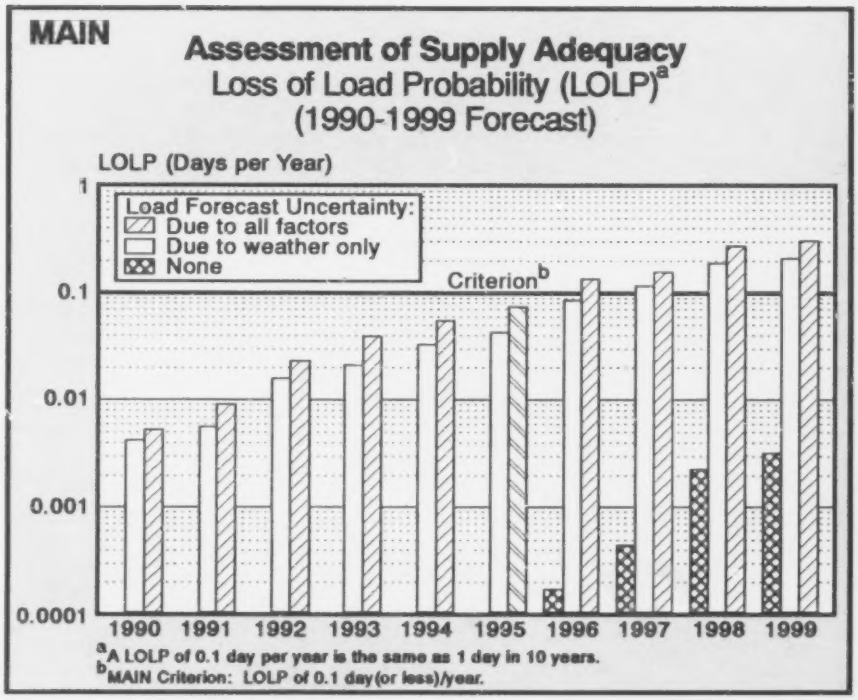
The generating reserve policy adopted by MAIN suggests that utilities maintain installed capacity at least 15% to 20% above the forecast peak demand in each year. This is equivalent to a capacity margin of 13% to 17%. Capacity margins as projected by MAIN are above minimum acceptable requirements throughout the forecast period, ranging from 21% in 1990 to 15.2% in 1999.

During the next ten years, summer peak demand is forecast to increase by 5,978 MW, while total installed capacity is expected to increase by 2,772 MW. Planned installed capacity in 1998 is 1,940 MW more in this year's forecast than in the 1989 forecast.

In general, the planned use of non-utility generators in MAIN is quite small, totaling only 187 MW in 1999. Planned load management increases from 41 MW in 1990 to 170 MW in 1999. Contractually interruptible demand increases from 843 MW in 1990 to 1,024 MW in 1999, which is 2.3% of MAIN's peak demand.

Net summer purchases and sales change from a net sale of 125 MW in 1990 to a net purchase of 29 MW in 1999. Of purchases totaling 341 MW in 1999, 114 MW are from unknown sources.

During the last five years of the forecast period, inoperable capacity is projected to be 28 MW.



In the recent past, when generation reserves were ample and electricity could be purchased at essentially the same cost as it could be produced by the outaged unit, MAIN utilities scheduled generator maintenance at time of summer peak. However, after 1991, no scheduled generator maintenance outages are planned over summer peak periods.

In summary, MAIN expects to meet its increased summer peak demands by adding short lead-time capacity, by minimizing inoperable capacity, by reducing exports, by eliminating scheduled maintenance at time of summer peak, by increasing contractually interruptible demand, by increasing load management, and by augmenting the capacity of some existing units.

Capacity adequacy in MAIN is assessed using loss of load probability (LOLP) analysis. The latest LOLP analysis, which covers the ten-year period ending in 1999, shows that without considering uncertainties due to weather and load forecast error, and with no more than 1,120 MW emergency imports from neighboring systems, generating capacity will be adequate to meet the MAIN expected LOLP criterion of 0.1 day (or less)/year throughout the ten-year study period. Considering uncertainties due to weather and load forecast error, this study shows that without improved utilization of existing resources or without adding additional resources MAIN may not be able to meet its LOLP criterion beginning in 1996. Consequently, MAIN is already investigating the effectiveness of various strategies to achieve this goal.

Transmission Adequacy

The transmission network in MAIN is adequate for reliable operation for both internal transfers and those involving adjoining Regions. Near-term operating studies, longer-term planning studies of interchange capability, and extreme disturbance studies are conducted on a regular basis to assure that transmission capacity will continue to be adequate. Each of these studies includes participation by representatives from adjacent Regions to provide interregional coordination.

Few new major transmission lines are planned in MAIN during the 1990-1999 forecast period. However, one planned 345 kV line is experiencing delay. The Albion-E. West Frankfort line will complete a 345 kV tie from the Gibson plant of Public Service of Indiana

to the Central Illinois Public Service Company transmission system at West Frankfort. This will constitute the third 345 kV circuit across southern Illinois, which is needed to reinforce the electric supply capability to a large area of southeastern Illinois. The line section was originally scheduled for completion in 1990. However, due to a lengthy regulatory approval process and significant landowner opposition, the line will not be in service until 1993.

Future Issues Influencing Reliability

Some critical concerns in MAIN that have the potential to adversely impact electric system reliability include:

- Acid Rain Legislation — Since coal is the major fuel used in MAIN for electricity production, additional legislative or regulatory requirements for reduced emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) may adversely affect the reliability of supply due to the following:

  - The maximum net output of most existing high sulfur coal units could be reduced 2% to 5% if retrofitted with facilities for SO_2 removal.

  - The average availability of retrofitted units may also decrease.

  - The installation of emissions control equipment often requires lengthy unit outages resulting in less capacity to serve customer demand during the periods of retrofitting.

  - It may not be possible, nor economic, to retrofit some older units, thus forcing premature retirement.

  - Unit capacity may be reduced due to burning low-sulfur coal.

  These factors could reduce the capacity available from existing coal units with the result that new replacement capacity will be required. As capacity margins approach minimal levels in the last half of the forecast period, these concerns become of increasing importance. If new regulations are developed to control acid rain, the cost and lead time for the required replacement capacity must be given suitable consideration.

- Application of Air Quality Standards to Maintenance Projects — With coal units providing over half of MAIN's generating capacity, it is extremely important that this existing capability be maintained in operable condition. The U.S. Environmental Protection Agency's (EPA) application of New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) regulations to maintenance projects, as in the case of Wisconsin Electric Power Company (WEPCo), could erode the capability of existing units or force their early retirement.

  WEPCo's Port Washington power plant has five coal-fired units each with an 80 MW nameplate capacity. The present rated capability of these units totals 270 MW. In July 1987, WEPCo requested permission from the Public Service Commission of Wisconsin to implement a maintenance program to return the plant's capacity to its 400 MW nameplate rating. The project was reviewed by the U.S. EPA who determined in October 1988 that NSPS and PSD air regulations apply to the project.

  In November 1988, WEPCo filed a request in the Seventh Circuit Court of Appeals for review of the EPA's determination. The court conducted its review and upheld the EPA's determination in January 1989.

  As a result of extended discussion between WEPCo and the EPA, one of the Port Washington units must meet full NSPS requirements and two units must have emissions controlled to some degree to avoid triggering NSPS. The two remaining units, whose full capacity rating had been confirmed in 1988, will not be subject to NSPS requirements. All five units will be subject to plant-wide PSD regulations.

  WEPCo has applied to the State of Wisconsin's Department of Natural Resources for an air emissions permit for four units at the Port Washington power plant and is expecting the permit in September 1990. WEPCo has decided not to renovate the unit that must meet the full NSPS requirement.

- Peak Demand Growth Above Forecast — MAIN's peak demand and annual energy forecasts are intended to have an equal probability of being high or low. The effects on reliability, however, are far from equal for actual peak demands higher or lower than forecast. If actual peak demands prove to be greater than forecast, utilities expect to encounter difficulty in adding transmission and generation capacity in a timely manner because of the present problems in siting and permitting. Concerns about the financing and timely recovery of costs for new generating capacity may also serve to delay new projects. Thus, the risk to reliability is accentuated. On the other hand, if peak demands are lower than forecast, there may be some adverse economic impact, but reliability would not be jeopardized.

- Capability of Manufacturers to Meet Utility Equipment Needs — With increasing numbers of utilities looking to combustion turbines as comparatively low capital cost, short lead-time capacity, there has been concern for a number of years about manufacturers' ability to supply utility requirements beginning in the mid-90s. Assurances of adequate capacity from manufacturers have not totally assuaged this concern. Similar concerns are now voiced regarding manufacturers' capability to meet utility needs for large high voltage transformers and circuit breakers. A sudden influx of orders for this equipment might not only delay new projects, but would also delay the repair or replacement of equipment that fails. These delays could seriously impact reliability.

- Operation With Lower Margins — Even though minimum reliability criteria will still be met, reliability levels will be lower than those in the recent past as generating capacity margins decrease from levels well above criteria toward minimum acceptable levels over the next ten years.

  As utilities operate closer to the lower limits of acceptable capacity margins, increased firm purchases and sales of capacity will replace the economy transactions that have predominated in the recent past. Curtailing firm capacity transactions due to transmission

system emergencies can impact customer reliability far more significantly than the past curtailments of economy energy transactions.

With less capacity margin available, flexibility in dealing with emergencies is reduced. In the past, the MAIN systems were capable of surviving multiple contingencies beyond the design level due to greater than planned margins. This capability will be less in the future.

The Mid-America Interconnected Network (MAIN) consists of 13 member systems and one associate member. MAIN is a summer peaking Region serving a population of 18 million in a geographic area of 170,000 square miles encompassing Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the upper peninsula of Michigan.

MAPP — Mid-Continent Area Power Pool

The existing and planned generation resources in the MAPP Region are anticipated to be adequate to reliably supply the projected demand requirements throughout the 1990-1999 review period. The capacity margin is projected to decline from 22.1% in 1990 to 17.1% in 1999, and is expected to be adequate for the entire assessment period.

A near-term reliability concern is the continuing drought conditions in the Region. Twenty percent of MAPP's generating capacity is hydroelectric. This capacity supplied 21% of the total electrical energy produced by the Region in 1989. Continuation of the drought could jeopardize this resource.

In the longer-term, a higher than projected peak demand could cause some reliability concerns near the end of the forecast period. Experience with load management in 1988 and 1989 has reinforced confidence in this strategy as a means of minimizing future capacity additions.

Actual		Forecast		
Summer	1989	1990	1999	Growth Rate
Winter	1989/90	1990/91	1999/00	(%/year)
MAPP-U.S.				
Summer Peak – MW	24,336	24,754	28,454	1.6
Winter Peak – MW	21,360	21,087	24,573	1.7
Annual Energy – GWh	122,982	125,476	148,643	1.9
Installed Capability (Summer) – MW	30,864	31,335	32,511	0.4
MAPP-Canada				
Summer Peak – MW	4,427	4,541	5,636	2.4
Winter Peak – MW	5,998	5,969	7,335	2.3
Annual Energy – GWh	32,157	32,204	40,041	2.4
Installed Capability (Winter) – MW	6,678	6,918	8,512	2.3
MAPP-Total				
Summer Peak – MW	28,763	29,295	34,090	1.7
Winter Peak – MW	27,358	27,056	31,908	1.8
Annual Energy – GWh	155,139	157,680	188,684	2.0
Installed Capability (Summer) – MW	37,385	38,036	40,990	0.8

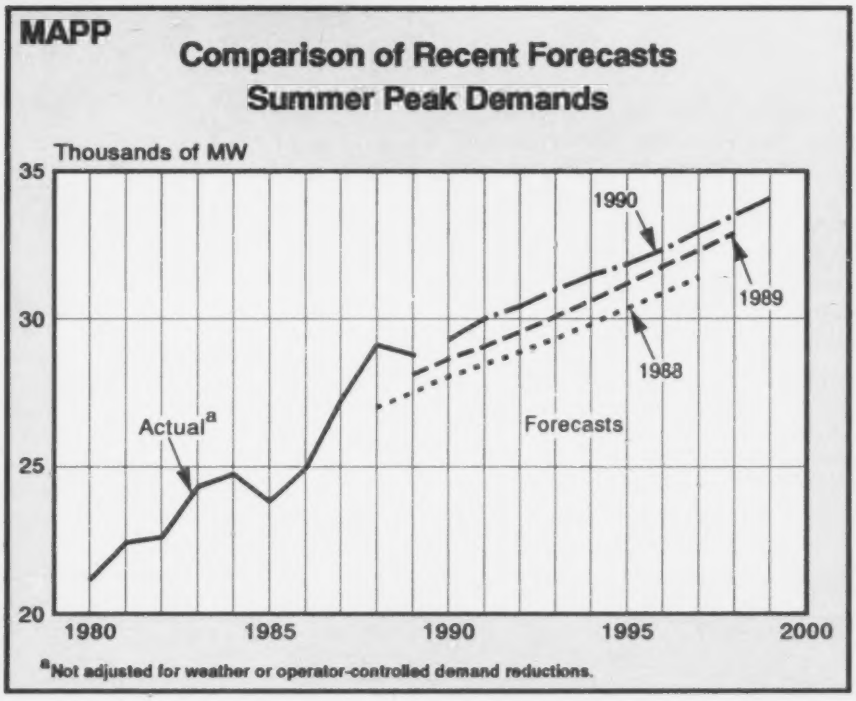
Peak Demand and Energy

The 1989 summer peak demand in the MAPP Region was 28,763 MW. The U.S. portion of the Region experienced a peak demand of 24,336 MW or 2.3% below the 1988 record peak demand, but 2.3% above that forecast in 1988 for the 1989 summer. The MAPP-Canada portion experienced a 1989/90 winter peak demand 9% above 1988/89 and 3.8% above forecast.

MAPP-U.S. is projecting essentially the same annual growth in both summer and winter peak demands as last year, but is projecting a slightly lower growth in annual net energy for load. MAPP-Canada is projecting a slightly lower annual growth in peak demand and energy compared to last year.

Actual peak demands and ten-year projections made in 1988, 1989, and 1990 are shown in the following figure.

MAPP peak demand and annual energy forecasts are the sum of the individual utility forecasts. MAPP-U.S. includes numerous smaller systems that are not members of the Pool. Their peak demands, net energy for load, and generating capacity have been included in this report for completeness. These other systems served a combined peak demand of 805 MW in 1989. This is projected to increase to 1,062 MW by 1999.



MAPP utilities continue to actively pursue various programs to reduce growth in peak demands. These include demand management, conservation, load management, and interruptible demands. Many of the effects of these programs are reflected in the projected peak demands and annual net energy for load. In addition to that already included in the projections, the MAPP utilities expect to be able to further reduce summer peak demands, if necessary, by 259 MW through load management and 93 MW through interruptible demands by 1999.

Capacity Resources Adequacy

The only major power plant under construction is the 1,200 MW hydroelectric plant in Manitoba, Canada with the first two 120 MW units scheduled to be placed in service during 1990 and the remaining eight units in 1991 and 1992. In addition, a 280 MW lignite-fueled unit in Saskatchewan is scheduled to be placed in service by the summer of 1992.

The utilities are planning to meet future peak demand growth through improved utilization of existing generating units and the addition of peaking capacity with over 800 MW of combustion turbines and combined cycle units being proposed. The only new coal-fired generators being proposed are a 400 MW unit in the United States in 1998 and a 280 MW lignite unit in Saskatchewan in 1996.

Through the purchase and exchange of existing capacity on a seasonal basis, nearly 1,000 MW of new generating capacity have been deferred beyond the reporting period.

MAPP-U.S. and MAPP-Canada depend primarily on nuclear, coal, and hydro for electrical energy production. In 1989, 15% of the total electrical energy produced was by nuclear generation, 21% by hydro, and 63% by coal. Less than 1% of the annual electrical energy was produced by oil or gas. This mix of energy production is anticipated to remain essentially the same throughout the reporting period. Non-utility generators form a minimal part in the capacity and energy resource plans for MAPP.

Projected peak demands and a range of projected available resources are shown for the MAPP Region in the figure on the next page. Adjustments for spinning reserve requirements and expected forced and scheduled outages of generating capacity based on MAPP's average statistics over a five-year period have been used to calculate the lower bound of the projected available resources. The upper bound represents the possible impact on projected available resources of reducing scheduled maintenance during peak demand periods. This figure illustrates the adequacy of the MAPP Region's generation capacity to meet the projected peak demand requirements. MAPP uses a sophisticated analytical method to determine required capacity margins in its regional reliability studies.

Transmission Adequacy

Transmission facilities are judged to be adequate through the ten-year review period.

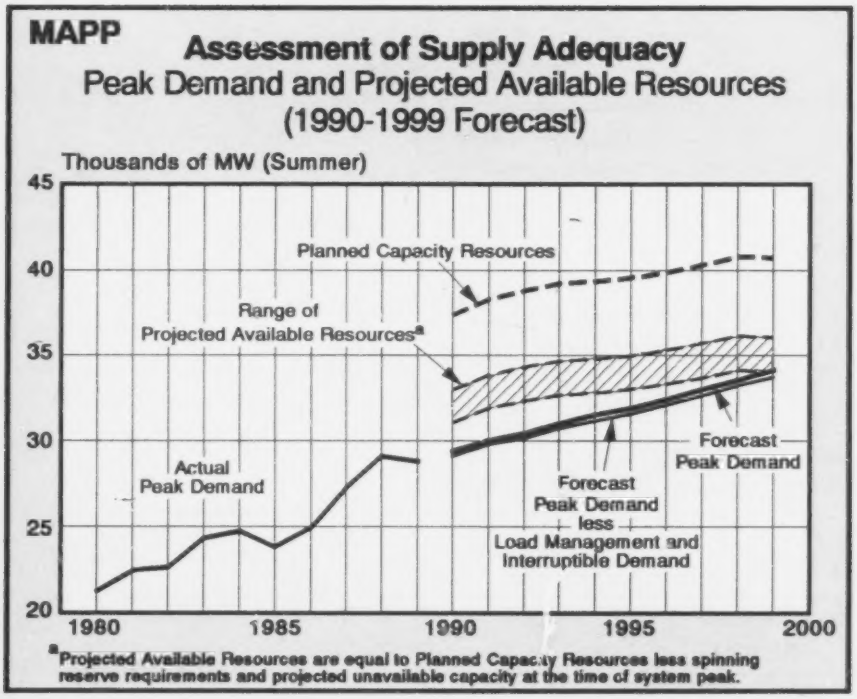
The MAPP utilities have 19,255 miles of ac and dc transmission lines 230 kV through 500 kV in service. Over the next ten years, plans call for the construction of an additional 1,564 miles of transmission lines 230 kV and above.

These additions include a new 345 kV interconnection between MAPP and SPP that is expected to increase transfer capability between the two Regions by approximately 1,000 MW, and a new interconnection between Manitoba and the United States that is planned to increase transfer capacity to the United States by at least 400 MW. Joint studies between utilities in MAPP and MAIN are currently under way to determine if additional transmission is desirable and justified to increase transfer capability.

The MAPP member utilities have made their transmission systems available to other MAPP members for MAPP transactions with no further compensation, except for losses, on the basis that every member has provided an equitable share of the total transmission required in MAPP. As a result, there are many energy transactions among the MAPP members and with adjacent Regions. In 1989, energy transactions amounted to 25% of the total net energy for load in the Region.

Reliability Issues

The major reliability issues in the MAPP Region are potential acid rain legislation, possible electric and magnetic fields regulations, increasing use of the



transmission systems for firm transactions, actual demand exceeding forecast, and fuel supply uncertainty.

- Acid Rain Legislation — Legislative efforts to further reduce emissions of sulfur dioxide, nitrogen oxides, and other substances from coal-fired power plants increases the uncertainty of the adequacy of the MAPP generating capacity. About 8,000 MW (35%) of MAPP's coal-fired generating capacity was installed prior to 1975. This capacity would be subject to:
  - Extended outages to retrofit additional emissions control systems,
  - Reduced capacity due to electric consumption of the additional equipment, and
  - Reduced availability because of increased complexity.
- Electric and Magnetic Fields Regulations — The present concern about possible adverse health effects of electric and magnetic fields could lead to regulations that have a potential of affecting the operation of MAPP's existing and planned transmission network. This could significantly reduce future reliability of supply.
- Transmission System Use — Increased utilization of the present generating capacity resources through seasonal diversity exchange agreements and capacity purchases increases the committed loading on the transmission network thereby reducing reliability margins. Further, greater dependency on the coordination and planning among the utilities becomes paramount to maintain reliability standards.
- Demand Exceeding Forecast — Although the MAPP Region did not exceed the 1988 summer peak demand, both MAPP-U.S. and MAPP-Canada exceeded the peak demand projected the prior year for 1989. As peak demands continue to grow, capacity margins become minimal toward the end of the forecast period. The possibility of actual peak demands exceeding forecast causes concern about the adequacy of generation supply. If this occurs, the viable resource options will most likely be limited to increased demand management and short lead-time peaking generating capacity.
- Fuel Supply Uncertainty — Although the MAPP utilities do not depend on fuel oil or natural gas for any significant amount of electricity production, they do have 10% of their electrical generating capacity dependent on oil and gas availability. Of greater near-term concern is the drought situation. The MAPP Region has 20% of its total generating capacity in hydroelectric plants, which in 1989 produced 21% of the total electrical energy produced in the Region. The continuing drought, in both the United States and Canada in the MAPP Region, threatens the reliability of this hydroelectric supply. In addition, the majority of the Region's large coal-fired and nuclear-fueled generating plants are dependent on adequate river flows to provide cooling.

The Mid-Continent Area Power Pool (MAPP) membership includes 43 systems. There are 27 participants consisting of 11 investor-owned systems, eight generation and transmission cooperatives, three public power districts, four municipal systems, and one federal agency. The associate participants consist of two Canadian Crown Corporations, 13 municipals, and one investor-owned system. The MAPP Region covers all or portions of the states of Iowa, Minnesota, Nebraska, North Dakota, Illinois, Michigan, Montana, South Dakota, and Wisconsin; and the provinces of Manitoba and Saskatchewan. Total geographic area served is 890,000 square miles with a population of 16 million.

NPCC — Northeast Power Coordinating Council

NPCC member systems are planning for adequate resources into the future through the use of a variety of resource options. These include additional utility and non-utility generating capacity, expanded demand management programs, and purchases from other utilities.

In New England, where currently planned resources are adequate through 1994, the New England Power Pool (NEPOOL) is now planning for the additional uncommitted and contingent resources it will need in the future to maintain its capacity resources requirement. Viable contingent and uncommitted resources, capable of being developed in the required time frame, have been identified well in excess of forecasted need.

Reliability of the transmission network depends on the timely completion of planned reinforcements, the location of non-utility generators, and continued coordination in operations.

	Actual		Forecast		
	Summer	1989	1990	1999	Growth Rate
	Winter	1989/90	1990/91	1999/00	(%/year)
NPCC-U.S.					
Summer Peak – MW		45,031	47,001	56,321	2.0
Winter Peak – MW		42,588	45,070	52,950	1.8
Annual Energy – GWh		253,866	257,394	302,517	1.8
Installed Capability (Summer) – MW		54,622	57,480	65,564	1.5
NPCC-Canada					
Summer Peak – MW		39,740	39,765	49,057	2.4
Winter Peak – MW		54,657	58,149	70,258	2.1
Annual Energy – GWh		308,650	310,273	389,600	2.6
Installed Capability (Winter) – MW		59,678	63,049	78,616	2.5
NPCC-Total					
Summer Peak – MW		84,771	86,766	105,378	2.2
Winter Peak – MW		97,245	103,219	123,208	2.0
Annual Energy – GWh		562,516	567,667	692,117	2.2
Installed Capability (Winter) – MW		116,670	123,058	146,217	1.9

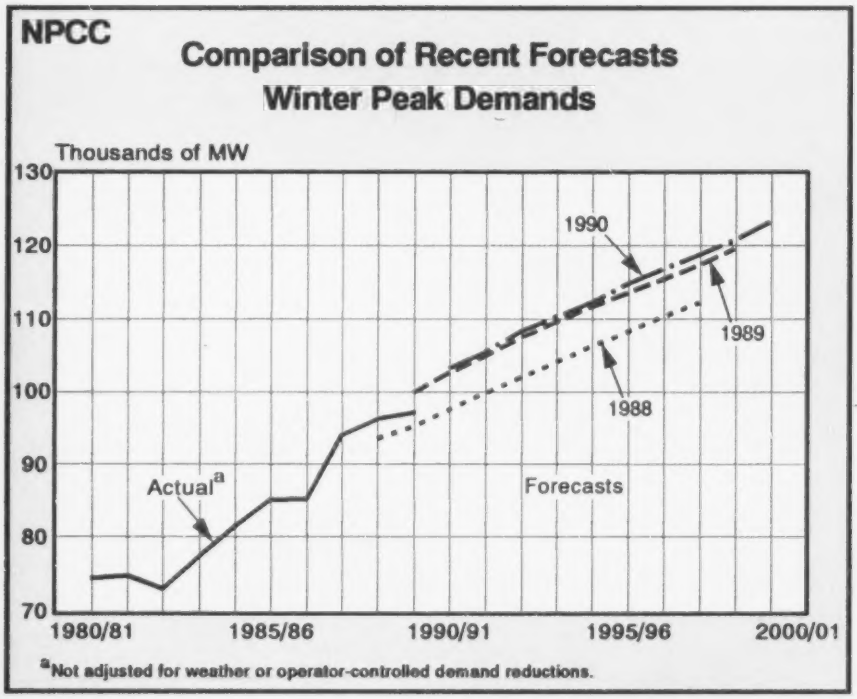
Peak Demand and Energy

For the U.S. members of NPCC, the summer peak demand in 1989 was slightly below the 1988 level and almost 4% below forecast. Milder than normal summer weather was the major factor. Annual electrical energy growth was 1.5% and just under forecast.

For the Canadian members of NPCC, the 1989/90 winter peak increased by 2.4% over the previous winter and was very nearly on forecast. Continuing a six-year trend, the 1989 summer peak was over forecast, this year by some 3%. Annual electrical energy growth was approximately 5.9% or 2.3% above forecast.

A comparison of actual winter peak demands for the NPCC Region and the forecasts made in 1988, 1989, and 1990 is shown in the following figure. The unadjusted NPCC actual winter peak demand for 1989/90 was approximately 2.7% below forecast.

The 1990 ten-year peak demand and annual electrical energy forecasts for NPCC have increased over the 1989 ten-year forecasts. The current NPCC winter peak demand forecast for 1998/99, the last common year of the ten-year forecasts, is virtually unchanged for NPCC-U.S. and approximately 2,800 MW or 4.2% higher for NPCC-Canada.



Resource Adequacy

A summary of the 1990-1999 net increases in NPCC resources by Area is shown in the table below.

Planned resources in New York, Ontario, Québec, and the Maritimes are adequate to meet forecast peak demands throughout the next ten years. This assumes that utility capacity plans, non-utility generator (NUG) projections, and demand management programs will be realized as scheduled. It also assumes that actual peak demand will not significantly exceed current forecasts.

Net Increase in NPCC Resources (%)
(1990-1999 Forecast)

Resource Options	New York	New England	Ontario	Québec	Maritimes[a]
Utility-Owned Capacity	5	21	54	73	96
Non-Utility Generators (NUGs)	58	16	10	3	3
Demand Management	22	28	34	21	1
Purchases from Other Utilities	15	2	2	3	0
Uncommitted and Contingent Resources	0	33	0	0	0
Total	100	100	100	100	100

[a]New Brunswick Electric Power Commission and Nova Scotia Power Corporation.

In New England, planned resources, which include commercial operation of Seabrook 1 (1,150 MW nuclear), 1,100 MW of non-utility generators, and approximately 2,000 MW of demand management, indicate adequate margins through the end of 1994. The New England Power Pool (NEPOOL) is now planning and in some instances has begun developing the additional uncommitted and contingent resources it will need beginning in 1995 to achieve a nominal 20% reserve margin (or a nominal 17% capacity margin).

Uncommitted and contingent resources are potentially available resources, including expansion of demand management programs, additional NUGs, additional utility purchases, or additional utility generating capacity, which are capable of being developed within the required time frame. Through the end of the 1999 forecast period, a total of 2,460 MW of "contingent resources" have been identified as being required. In comparison, NEPOOL has identified as a part of its annual resource adequacy assessment some 8,890 MW of viable contingent and uncommitted resources as being potentially available through the end of 1999.

In New York, planned resources, which reflect for the first time generating capacity from newly instituted bidding programs, include the reactivation of Nine Mile Point 1 (605 MW nuclear) for the summer 1990, a Niagara hydro capacity expansion of 330 MW for the summer of 1997, an additional 67 MW of small hydro, and approximately 4,700 MW from non-utility generators (including some 1,020 MW of bidding program capacity). Demand management options are estimated to reduce the projected peak demand by 1,850 MW by the end of the forecast period.

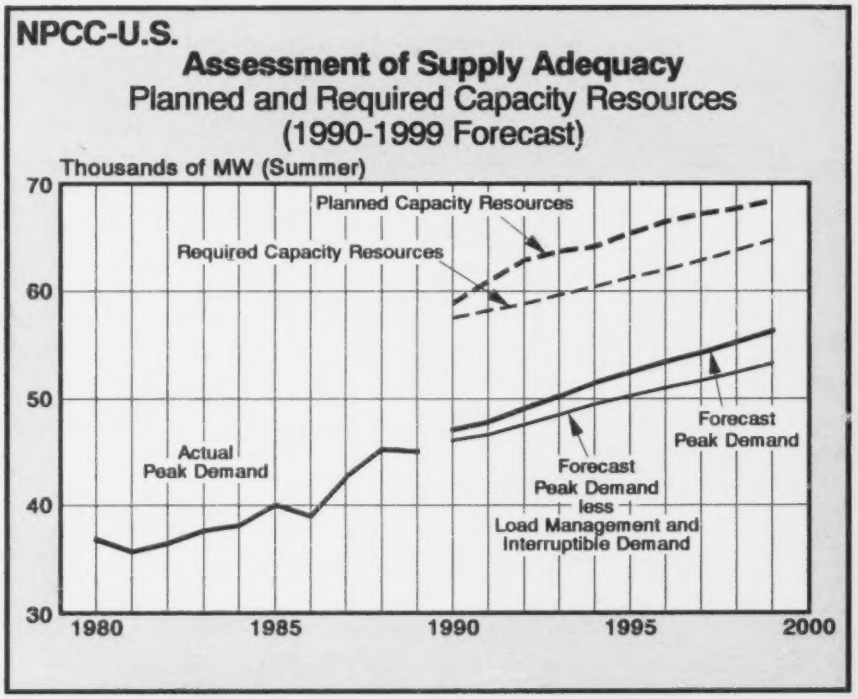
New York's firm transactions with Hydro-Québec include a winter sale of 400 MW to Hydro-Québec, and a 500 MW purchase from Hydro-Québec commencing in the summer of 1995 and increasing to 1,000 MW in the summer of 1996 for the remainder of the forecast period. The existing 800 MW summer purchase from Hydro-Québec will continue throughout the assessment period.

In Ontario, four 881 MW nuclear units are under construction at the Darlington plant and are scheduled to come into service between 1990 and 1992. Ontario Hydro has developed a comprehensive demand/supply resource plan covering the period up to 2014. It includes a balance of demand management, non-utility generation, hydroelectric development, firm purchases, and major generating capacity supply alternatives to meet the anticipated resource requirements. The plan, which is currently the subject of public hearings provides for low, median, and high peak demand growth scenarios. While project commitments will be made from the plan on the basis of the median growth forecast, studies and approval processes are being initiated assuming the high growth forecast.

In Québec, where 95% of the electrical energy is supplied by hydro, reserve levels continued to decline due to persistent adverse hydro conditions. As a result of low water conditions and sustained growth in electrical energy use (7.1% growth in 1989), construction of additional hydroelectric generating facilities has been advanced as much as possible.

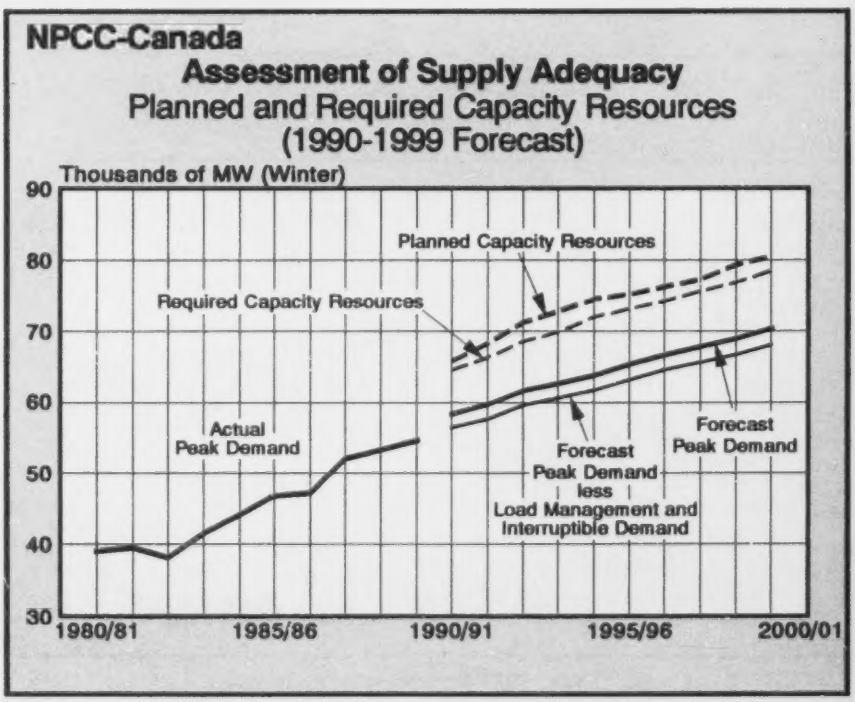
For the short term, Hydro-Québec has taken actions to maintain its ability to meet its future firm peak demand under a prolonged drought situation. These actions include the reduction of sales, the buyback of industrial dual energy contracts, the generation of thermal energy, and supplemental purchases from neighboring systems. Hydro-Québec forecasts that these actions will add 10,000 gigawatt hours to its electrical energy during 1990, and anticipates, assuming average rainfall, that by 1995 water reserve levels will return to normal.

For the longer term, Hydro-Québec has developed resource plans to accommodate weak, average, or strong demand growth scenarios. Hydro-Québec's base development plan includes the construction of over 5,000 MW of additional hydro capacity between 1995 and 2000. Furthermore, it projects annual electrical energy savings of nearly 13,000 gigawatt hours by 1999 through conservation and efficiency measures.



In the Maritimes, approximately 2,200 MW of additional coal-fired generators and some 700 MW of gas-fired generators are scheduled for installation throughout the forecast period.

The adjacent figures provide an overall adequacy assessment of the planned capacity resources for NPCC-U.S. (summer) and NPCC-Canada (winter). The required capacity resources for



each NPCC Area were calculated individually utilizing the probabilistic techniques employed by each Area and were then totalled for comparison with the planned capacity resources.

Transmission Adequacy

The New England, New York, Ontario, and New Brunswick systems meet NPCC transmission criteria, and will continue to do so throughout the forecast period. When Hydro-Québec and Nova Scotia Power Corporation joined NPCC, it was with the understanding that although their systems did not satisfy all of the provisions of the NPCC criteria, contingencies on their systems would not be allowed to have a significant adverse impact on the other NPCC systems. As a result, operating restrictions are currently in place that limit transfers between Hydro-Québec and the remainder of NPCC. A major system enhancement program involving series compensation of virtually all existing 735 kV lines is planned by Hydro-Québec to bring its system into conformance with the NPCC criteria.

In the Canadian Areas of NPCC, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total 6,856 miles. By contrast, in the U.S. Areas of NPCC, planned transmission additions total 574 miles. Of this increase, some 133 miles are associated with the NEPOOL—Hydro-Québec Phase II interconnection, which is scheduled for completion in 1990. This lack of construction of new transmission in NPCC-U.S. means that the existing New York and New England transmission systems could experience increased loadings as peak demands continue to grow.

On Long Island, a new transmission interconnection from the upstate New York 345 kV grid to the Hempstead area is scheduled to go into service before the summer of 1991. This new interconnection will result in significantly improved reliability for the Long Island area.

Operations

Coordination in operations within NPCC is achieved through a hierarchical system. Criteria, guides, and procedures developed at the NPCC level are expanded and implemented at the Area level by the two U.S. power pools and four Canadian member systems. Each of the U.S. pools and Canadian systems operates a centralized control center for economic dispatch, overall system monitoring, and control.

In New England, control proceeds from the New England Power Exchange (NEPEX) dispatch center to satellite centers and then to individual utilities. In New York, control proceeds from the New York Power Pool (NYPP) dispatch center to the utilities. Telecommunication systems and computer networks link NEPEX, NYPP, and the Canadian control systems with each other and with neighboring systems in other Regions.

In recent years, loadings on the bulk transmission systems in NPCC have increased in part due to large economy energy transfers. To maintain reliable system performance, intraregional and interregional communications have also been increased. Through a "Procedure for Special Communications," weekly updates of interpool capacity margins are exchanged and conference calls are held among system operators in anticipation of emergency conditions.

In addition, NPCC recently developed "Procedures for Solar Magnetic Disturbances on Electrical Power Systems." NPCC Areas receive solar magnetic disturbance forecasts and alerts from two agencies, the Space Environment Service Center in Boulder, Colorado, and Energy, Mines and Resources in Ottawa, Canada. On receiving notification of a solar magnetic disturbance of K7 or higher, existing and planned operations are reviewed for vulnerability to such storms.

Interpool coordination agreements exist among the NPCC Areas and with neighboring systems. Further, NPCC is a party to Inter-Area Coordination Agreements with MAAC and ECAR. Through these and a similar agreement among MAAC, ECAR, and the Virginia-Carolinas (VACAR) subregion of SERC, studies are regularly conducted among MAAC, ECAR, and NPCC (MEN), and VACAR, ECAR, and MAAC (VEM). All are performed under the auspices of a permanent Joint Interregional Review Committee made up of representatives from ECAR, MAAC, NPCC, and VACAR.

Reliability Issues

A significant amount of non-utility generating capacity and demand management has been included in the projected resources for the next ten years, especially in New York, New England, and Ontario. Concerns regarding the dependability of these options on a long-term basis, and their availability during peak demand periods, increase the uncertainties inherent in resource planning.

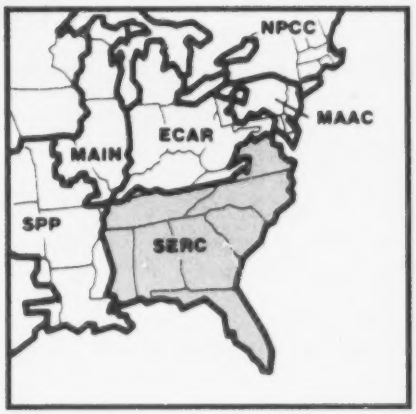
It is estimated that electrical energy from non-utility generators will increase from approximately 16,000 gigawatt hours or 3% of total NPCC energy in 1990 to approximately 49,000 gigawatt hours or 8% by 1994 — a projected growth rate of over 30% per year. The majority of this projected increase occurs in New York. By the end of the forecast period, it is estimated that 53,000 gigawatt hours of electrical energy will be supplied by NUGs.

Further, gas-fired capacity is projected to supply over 40% of the electrical energy produced by NUGs in 1999. If all the future NUG capacity, which is currently listed with an unknown fuel type, were to be supplied by natural gas, the gas component would increase to approximately 70% of NUG supplied electrical energy. The long-term availability and deliverability of natural gas for NUGs is a concern.

The foregoing analysis of projected natural gas utilization does not include the impact of clean air legislation in the United States. The probable effects of tightened environmental restrictions will be to increase natural gas use even further.

The Northeast Power Coordinating Council (NPCC) represents 23 investor and publicly-owned utilities serving about 44 million people in a one million square mile area encompassing the northeastern United States and eastern Canada. In the United States, NPCC members participate in either the New England Power Pool (NEPOOL) or the New York Power Pool (NYPP), which constitute two of NPCC's five Areas. In Canada, Ontario Hydro, Hydro-Québec, New Brunswick Power, and Nova Scotia Power are province-wide systems and make up three of NPCC's Areas — Ontario, Québec, and the Maritimes.

SERC — Southeastern Electric Reliability Council



Projected capacity margins in SERC are judged to be adequate during the review period based on current resource expansion schedules and peak demand and annual electrical energy projections. However, if peak demands exceed current projections, a deficiency in generation supply capability could quickly develop. Maintaining adequate capacity margins depends on planned capacity additions coming on-line as scheduled and continued high availability of existing generators. More than 38% of the planned capacity additions in the next ten years will be combustion turbine and combined cycle units. Also, the SERC systems continue to increase their conservation and load management programs. Approximately 5,238 MW of operator-controlled load management and interruptible demand, representing 3.4% of peak demand, are planned to be available to reduce 1999 summer peak demand.

The SERC transmission systems are capable of supplying contractually scheduled capacity transfers and additional emergency transfers among the SERC subregions, and between SERC and other Regions. However, the increasing use of the transmission systems by many utilities simultaneously has resulted in heavy loadings on critical lines that limit interregional economy energy transfer capability. Coordinated planning and operations must continue among SERC and neighboring Regions to ensure that adequate reliability is maintained.

	Actual		Forecast		
	Summer	1989	1990	1999	Growth Rate
	Winter	1989/90	1990/91	1999/00	(%/year)
Summer Peak – MW		117,051	121,636	154,983	2.7
Winter Peak – MW		121,995	117,810	150,196	2.7
Annual Energy – GWh		623,230	641,920	810,337	2.6
Installed Capability (Summer) – MW		143,325	145,047	176,370	2.2

Peak Demand and Energy

The 1989 summer peak demand increased 1.6% over 1988, slightly exceeding the forecast by 1%. Annual electrical energy increased 4.9% in 1989 and exceeded forecast by 2.1%.

The 1990-1999 forecast of average annual growth in summer peak demand has increased from last year's 2.6% to 2.7%. The summer peak demand projected for 1998 (the last common year of the past two forecasts) is 6,333 MW higher than projected last year. The winter peak demand and annual electrical energy growth rates have also increased over last year's forecast. The following figure illustrates the growth in actual summer peak demand compared to ten-year peak demand projections made in 1988, 1989, and 1990.

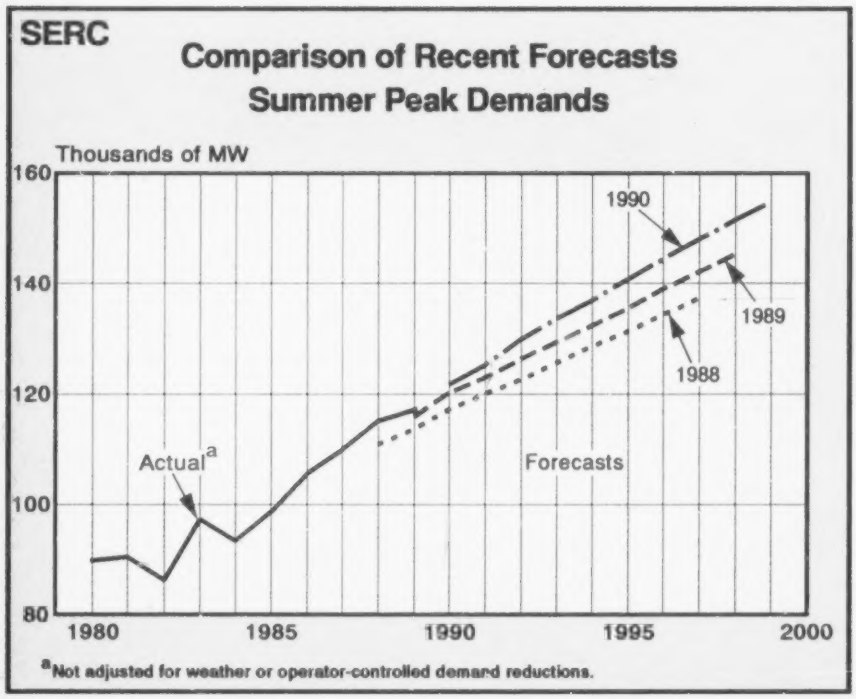
Load management programs continue to be pursued by member systems at about the same rate as projected last year. Operator-controlled load management, which includes contractually interruptible customer demands, is expected to provide 5,238 MW of summer peak demand reduction capability by 1999.

Capacity Resources Adequacy

Net capacity additions within SERC for the 1990-1999 period include 5,755 MW of coal-fired units, 3,575 MW of nuclear units, 2,605 MW of pumped storage units, 12,701 MW of combustion turbine/combined cycled units, and 4,289 MW of other or unspecified categories. In addition, 3,966 MW of non-utility generators are projected to be added during the period. This results in total capacity additions of 33,045 MW.

Most of the large baseload units projected to come on-line during this assessment period are well under construction with near-term operating dates. During the later years of the forecast period, because of system characteristics and regulatory and financial concerns, many systems are planning on peaking or intermediate type capacity such as combustion turbines and combined cycle units, and capacity purchases from non-utility generators.

Non-utility generators (NUGs) will increase significantly in the coming years for some SERC systems. Experience has indicated that not all proposed and/or contracted NUGs will be available as scheduled. Thus, some organizations within SERC are applying discount factors to account for this probability of installation. Contractual provisions are



being negotiated to ensure the long-term and high availability of NUG capacity during peak demand periods and to ensure the proper integration of NUG capacity into the transmission network to prevent degradation of system reliability.

Projected capacity margins in SERC are judged to be adequate during the review period, based on current generating capacity expansion schedules and peak demand and annual energy projections. Capacity margins for 1990, 1995, and 1999 are 17.9%, 16.6%, and 15.5%, respectively. However, if peak demand continues to exceed forecast, or if projected resources do not materialize as planned, capacity margins could quickly become less than adequate. Successful implementation of planned load management programs will be critical to the reliability of the SERC systems. A comparison of projected peak demands and projected available resources is shown in the figure on the next page.

Some additional capacity resources are presently in the early planning stages. Therefore, current projections do not include the total amount of capacity that will be added. These additional units are expected to come on-line in the latter half of this assessment period.

In addition to the installation of new capacity, modifications to existing units are under way and include unit upgrades, availability improvement programs, and reactivation of mothballed units. Electric supply adequacy would be adversely impacted by regulatory decisions or other factors that would restrict the availability of existing or planned generating capacity.

Transmission Adequacy

The existing transmission systems include 19,676 miles of 230 kV and 7,609 miles of 500 kV transmission lines. Approximately 1,902 miles of 230 kV and 755 miles of 500 kV lines are expected to be added in the 1990-99 period.

Economic capacity transactions at the ECAR, MAAC, and SERC transmission interface must be curtailed or constrained at times to prevent voltages dropping below defined acceptable limits or line loadings exceeding thermal limits. A number of joint studies have been undertaken to identify methods of strengthening this interface. As a result of these studies, Virginia Power (SERC) and American Electric Power Service Corporation (ECAR) have reached agreement in principle on a major transmission improvement that includes approximately 102 miles of new 500 kV line and approximately 110 miles of 765 kV line. The necessary permitting, route investigation, and detailed engineering activities for the improvement have begun. Completion of these additions is scheduled for 1998.

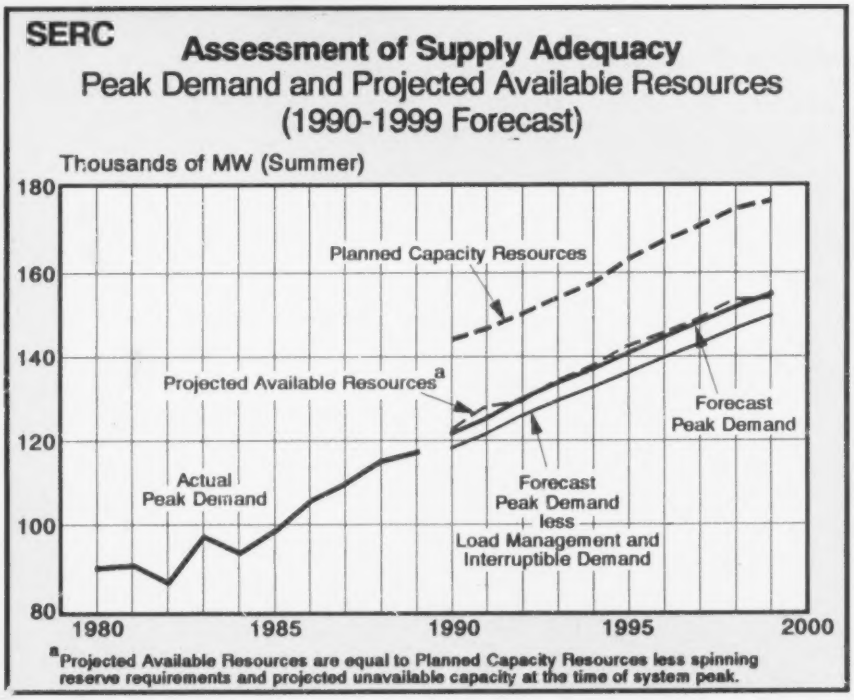
In December 1986, the final VACAR section of the Washington, D.C., 500 kV loop was completed. However, remaining sections of the loop will not be completed until 1994. This 500 kV loop is vital to the reliability of the bulk electric supply to the Washington, D.C. area and to the transfer capability among ECAR, MAAC, and SERC Regions.

SERC systems have coordinated transmission planning and operations to assure the continued use and expansion of a reliable transmission network. SERC is directly interconnected with the transmission systems in four other Regional Councils (SPP, MAIN, ECAR, and MAAC), and SERC members actively participate in inter- and intraregional transmission studies. Results of these studies indicate that existing facilities, along with those planned to meet the future reliability needs of the SERC subregions, will provide adequate emergency transfer capability between SERC and other Regions and among the SERC subregions. All systems within SERC expect to meet SERC reliability criteria during the review period.

Operations

The bulk electric transmission network ten years from now will not be significantly different from the present day. The transmission systems are basically in place for most of the new capacity that is planned. Moderate demand growth and the sharing of generation capacity will reduce operating margins throughout this period. As NUG and load management programs become significant elements in electric supply, operating strategies will be modified in recognition of their specific characteristics. More frequent use of operating procedures involving these resources will become a normal part of system operations to ensure that system reliability is maintained.

Detailed near-term operating studies and longer range planning studies are



made on a regular basis to ensure that transmission capacity will continue to be adequate. These studies involve representatives from each of the SERC subregions and from adjacent Regions to provide interregional coordination.

Regional Reliability Issues

The key reliability issues of concern to the SERC systems are:

- Forecast Uncertainty — Actual peak demand in SERC has been higher than projected for the past five years. Projected annual peak demand growth rates since 1984 have ranged between 2.2% and 2.7%. However, actual annual growth has averaged 4.6% from 1984 to 1989. Annual electrical energy growth averaged 4.8% during this same period. Systems within SERC have been able to maintain reliable service during this period in part due to the high level of generating capacity margins that existed in 1984. However, reserves, as measured by capacity margin, have declined from 26.8% in 1984 to 18.3% in 1989. Should actual demand growth continue to exceed projections in the early 1990s as it did in the late 1980s, the SERC systems will have much lower capacity margins to accommodate this growth and reliability could be adversely affected.

- Transmission Utilization — Near-term economy transactions involving the transfer of large blocks of capacity are being scheduled on a more frequent basis than in past years. The increased loadings on the transmission systems continue to be a major concern due to the potential impacts to system reliability from increased operating complexity and potentially more severe consequences during system contingencies.

- Weather Related Events — Weather related events can have major impacts on the reliability of electric systems. This is due to the fact that extremes of temperature can cause peak demands to greatly exceed those that are forecast based on normal weather conditions, and that electric supply facilities are vulnerable to damage caused by storms. The SERC Region was severely impacted by both of these factors in 1989.

Just prior to the 1989 Christmas holiday, the SERC Region experienced record low temperatures. Peak demand exceeded the 1989/90 winter peak forecast by 6.4%. All subregions exceeded their forecasts due to the record cold. In addition to the exceptionally high peak demands, several generating units were forced out of service due to freeze-ups, curtailment of natural gas fuel supplies, and other mechanical failures. Florida utilities were forced to interrupt service to customers on a rotating basis for several hours. Up to 5,000 MW of customer demand was interrupted or otherwise not served. All other subregions were able to supply their customer demands and the Southern Subregion provided over 9,000 MW to other SERC systems.

Hurricane Hugo struck the Virginia-Carolinas (VACAR) Subregion of SERC in the pre-dawn hours on September 22, 1989. Packing winds of 135-139 miles per hour, the storm made landfall just north of Charleston, South Carolina, passed through Columbia and was then downgraded to a tropical storm after passing through Charlotte, North Carolina. The hurricane caused extensive damage to utility systems in its path and left over a million and a quarter customers in North and South Carolina without electric service. Near the coast and for some distance inland, the 115 kV and 230 kV transmission lines were severely damaged and distribution systems were essentially destroyed. Further inland, damage was mainly to distribution systems, although some transmission was also damaged. Relatively minor damage was sustained at several generating stations. Despite the extensive damage to the transmission system, the remaining portions of the SERC interconnected systems were able to avoid cascading transmission outages and continued in service throughout the storm.

Affected systems immediately mobilized their manpower and material resources and called on other systems to speed electric service restoration. Twenty-two utilities from outside VACAR responded. Over 6,570 workers from contractors and other utilities, from as far away as Illinois and Maine, assisted the VACAR utilities in rebuilding their electric systems. Working day and night, electric service was restored to nearly all customers capable of receiving it by October 7.

While it is not possible to totally eliminate the adverse reliability impacts of severe weather, coordinated planning and operations of the bulk electric systems can minimize these impacts.

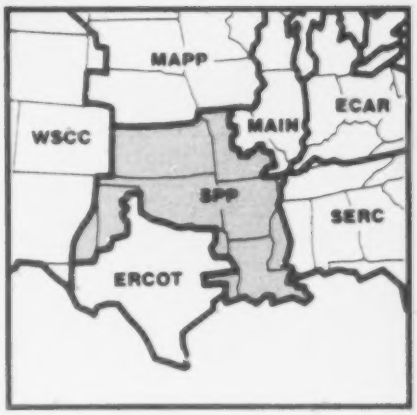
- Environmental Issues — The major environmental issues causing concern among the systems in SERC are acid rain and electromagnetic field (EMF) effects.

  Both the U.S. House of Representatives and the Senate have passed amendments to the U.S. Clean Air Act. This legislation is expected to have a significant impact on the availability of existing fossil-fired generating units with an associated cost to the ratepayer. Many systems in SERC continue to be actively involved in projects to identify the significance of acid rain legislation in their areas including the effects of emissions control equipment retrofits.

  Electric and magnetic fields concerns and associated publicity are appearing in many parts of the country. In January 1989, the Florida Environmental Regulation Commission passed the nation's first standards regulating the strength of magnetic fields from electric utility power lines. Florida also became the seventh state to pass electric field limitations.

SERC membership includes 29 systems located in nine states in the southeastern United States. SERC, covering an area of 345,650 square miles, is divided into four diverse subregions that are identified as Florida (the Florida peninsula), Southern (the geographical area of the Southern electric system), TVA (the Tennessee Valley Authority area), and VACAR (the Virginia-Carolinas area). Total population in the Region is about 45 million.

SPP — Southwest Power Pool



With the present forecast of demand growth and capacity additions, SPP will meet its capacity margin requirements throughout the forecast period. Despite a depressed economy and below normal temperatures in 1989, the Southwest Power Pool experienced a peak demand 0.2% greater than in 1988. The 1990 forecast for the next ten years is for a 1.9% average annual demand growth, slightly lower than the 2% growth projected last year. Annual electrical energy growth is projected to be 2%.

Studies of the transmission systems indicate a reliable network for all simulated first contingency conditions. There are no anticipated bulk transmission reliability concerns and the simultaneous first contingency incremental import capability is 3,700 MW.

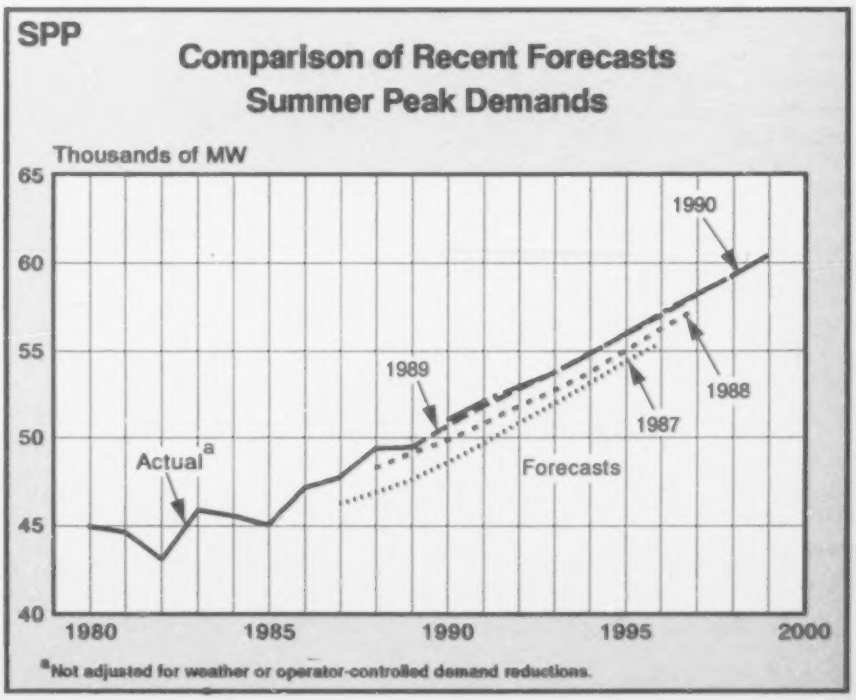
Reliability concerns include greater than anticipated peak demand growth, possible environmental legislation, and fuel deliverability.

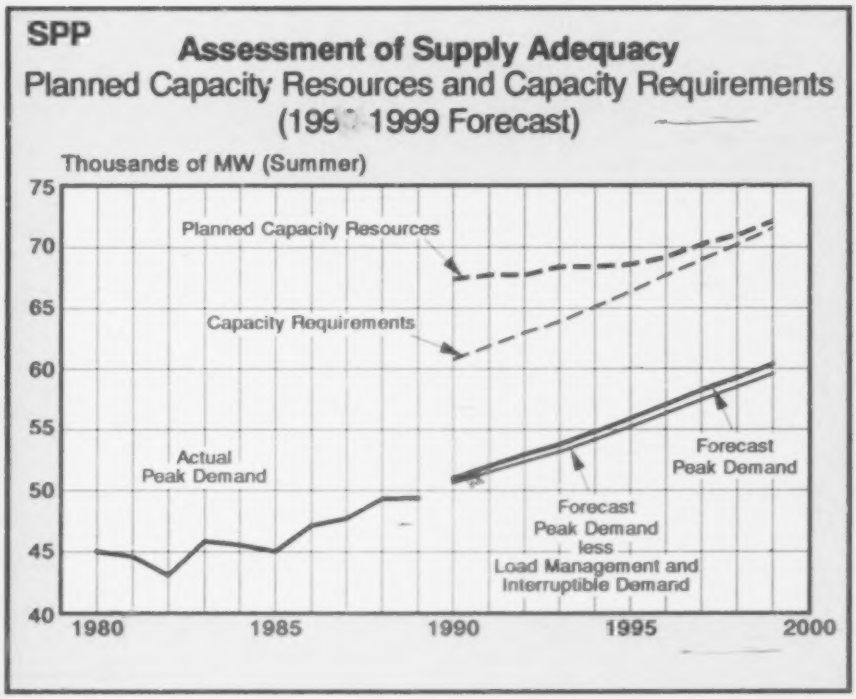
	Actual		Forecast		
	Summer	1989	1990	1999	Growth Rate
	Winter	1989/90	1990/91	1999/00	(%/year)
Summer Peak – MW		49,439	51,030	60,404	1.9
Winter Peak – MW		42,268	38,731	46,832	2.1
Annual Energy – GWh		243,805	244,330	292,820	2.0
Installed Capability (Summer) – MW		66,625	67,460	71,235	0.6

Peak Demand and Energy

In four of the five years between 1981 and 1985, peak demand decreased from the previous year. However, since 1985, the Southwest Power Pool (SPP) has experienced four consecutive years of peak demand growth. Despite a depressed economy and below normal temperatures, the 1989 summer peak demand was as forecast and exceeded the 1988 peak by 0.2%. This compares with an average annual increase for the past four years of 2.4%. Actual peak demands and ten-year projections made in 1987, 1988, 1989, and 1990 are shown in the adjacent figure.

The 1990 forecast of the 1990 summer peak demand was increased by 366 MW from the 1989 forecast. However, with the slightly lower forecast growth for annual summer peak demands, the 1990-1999 summer peak demand forecast is nearly identical to the 1989-1998 forecast made last year. The peak demands of the SPP subregions are projected to increase at rates of 2.4% for the North-





east, 2% for the West-Central, and 1.5% for the Southeast.

Annual electrical energy use is forecast to increase at a rate of 2%. This is unchanged from last year's projection.

Capacity Resources Adequacy

Presently, SPP has ample generating capacity to serve its peak demand requirements. Between 1989 and 1999 it is projected that total installed capacity will increase by 4,610 MW to 71,235 MW. This increase includes 800 MW of new steam capacity, including one 500 MW baseload unit, and over 1,760 MW of reactivated steam units. During this period, 460 MW of new non-utility capacity are anticipated and nearly 600 MW of combustion turbine and combined cycle units will be installed.

With the present demand and capacity projections, capacity margins will meet the SPP criteria of 16.7% throughout this forecast period.

The SPP fuel mix remains fairly constant over the next ten years with coal supply accounting for 58%, gas and oil 24%, and nuclear roughly 15% of the total electrical energy production. At the present time, there are adequate supplies of fossil fuels for the forecast period. However, regulatory action could result in serious capacity problems for the utilities of SPP with such a significant amount of coal, gas and oil, and nuclear generation.

Transmission Adequacy

Since last year's assessment, the only major transmission line placed in service was 75 miles of 345 kV from GRDA Generating Station to Tulsa North Substation to Cleveland Substation, all in northeast Oklahoma.

Three utilities of SPP and four utilities in MAPP have agreed to build a 105-mile 345 kV interregional transmission line in northwest Missouri and southeast Nebraska. This facility is to be completed in 1992. It will provide additional transfer capacity between the two Regions and relieve a first contingency transfer constraint that has existed for some time.

The above line is included in the next five year transmission projection of 293 miles of 230 kV, 326 miles of 345 kV, and 14 miles of 500 kV. Between 1995 and 1999, 122 miles of 230 kV, 236 miles of 345 kV, and 154 miles of 500 kV are planned. In addition, a 600 MW dc tie between ERCOT and SPP, located in northeast Texas is planned to be in service in 1995.

Transfer capability with adjacent Regions of the Eastern Interconnection remain adequate throughout the forecast period. Non-simultaneous first contingency incremental transfer capability imports range from 425 MW to 3,275 MW and exports range from 750 MW to 3,275 MW with these adjacent Regions. Simultaneous first contingency incremental import capacity for SPP is 3,700 MW or greater throughout the forecast period.

Reliability Issues

A number of reliability issues concern the SPP members. Perhaps the most significant is the impact of greater than anticipated peak demand growth. If the 1.9% growth in projected peak demand should increase at a rate of 2.5% and if purchases and demand management are only half as effective as planned, then it would appear that SPP will be short of meeting its capacity margin requirements by 1995.

If accelerated demand growth does materialize, member systems will return a number of mothballed units to service sooner than planned, and will install combustion turbines and combined cycle units earlier than anticipated.

With 58% of the electrical energy predicted to be supplied by coal, legislation on acid rain becomes very significant. If the regulations are too severe, then a number of existing older coal-fired units may be retired. With significant numbers of gas-fired combustion turbines planned, the ability of fuel suppliers to deliver natural gas with existing pipe line capacity is questionable. Also, with approximately 15% of the electrical energy to be produced by nuclear fuels, legislation concerning nuclear waste could have a severe impact in SPP.

Reliability is a concern with any regulations that involve transmission service and the use of SPP members' transmission systems by NUGs and others. The member systems that own

and operate a transmission network must be permitted to operate that network in the most reliable manner with economic generation considerations being determined by the utility owners.

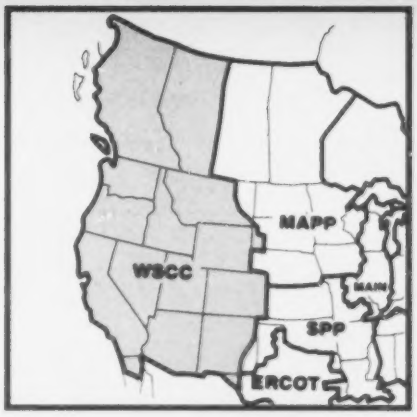
Operations

The transmission network is designed to be reliable for all single contingency conditions. There are several isolated, local area limitations that are closely monitored and when required, operating guidelines are implemented to reduce line loadings during contingency situations. At times, parallel path or loop flow in the Middle South Electric Systems, TVA, and Southern Company interface must be closely monitored and controlled.

The Pool has placed a new computer communications system in service. This replaces a system that has been in service for ten years and will allow for improved member access and automated data exchange. A new computerized system has also been made available to member systems for monthly reporting of generator performance.

The Southwest Power Pool (SPP) includes 44 electric suppliers serving customers in the states of Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas, and New Mexico. The membership is comprised of 17 investor-owned utilities, 12 municipal systems, 11 generating and transmission cooperative systems, three state authorities, and a federal agency. SPP currently serves more than 6.6 million customers and covers a geographic area of 500,000 square miles with a population of over 25 million.

WSCC — Western Systems Coordinating Council



The WSCC member systems continue to be optimistic regarding the outlook for reliability within the Region. WSCC's supply of electricity and its transmission network are projected to be adequate in serving the forecast growth in customer electrical requirements during the next ten years. Although issues such as competition, electric and magnetic fields, and demand forecast uncertainty continue to pose challenges in maintaining reliability, the WSCC members believe that these issues can be reasonably managed to avoid degradation of reliability through the cooperative efforts of utilities, non-utilities, and the regulatory community.

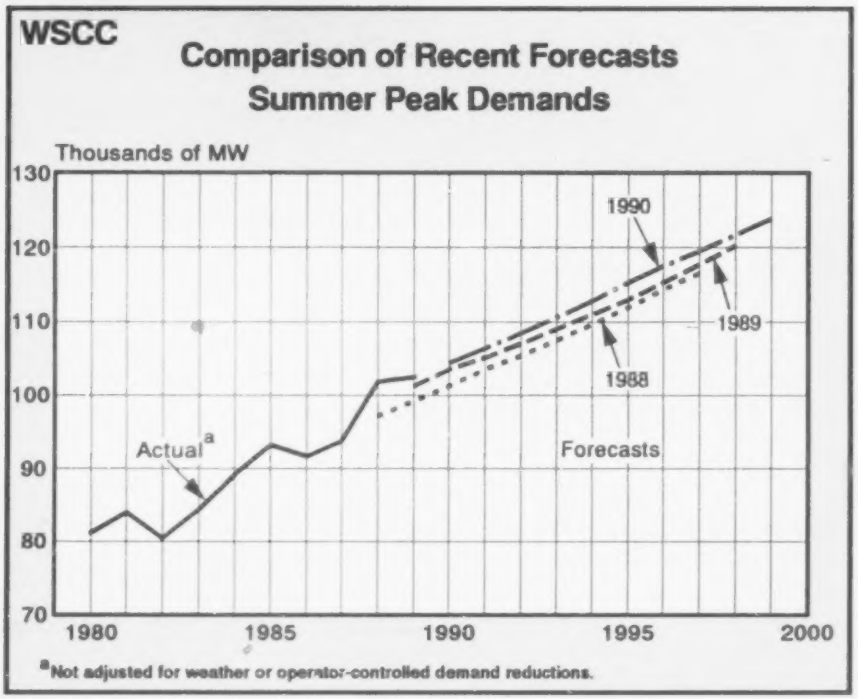
Actual		Forecast		
Summer	1989	1990	1999	Growth Rate
Winter	1989/90	1990/91	1999/00	(%/year)
WSCC-U.S.				
Summer Peak – MW	90,657	92,168	108,267	1.8
Winter Peak – MW	84,768	88,754	103,767	1.8
Annual Energy – GWh	540,498	547,970	642,311	1.8
Installed Capability (Summer) – MW	129,533	126,478	136,058	0.8
WSCC-Canada				
Summer Peak – MW	11,105	11,487	14,042	2.3
Winter Peak – MW	13,888	14,493	18,060	2.5
Annual Energy – GWh	85,286	89,445	112,972	2.6
Installed Capability (Winter) – MW	18,335	18,631	20,587	1.1
WSCC-Mexico				
Summer Peak – MW	817	874	1,675	7.5
Winter Peak – MW	556	607	1,146	7.3
Annual Energy – GWh	4,075	4,404	9,174	8.5
Installed Capability (Summer) – MW	1,030	1,180	1,706	4.2
WSCC-Total				
Summer Peak – MW	102,496	104,349	123,951	1.9
Winter Peak – MW	99,212	103,494	122,708	1.9
Annual Energy – GWh	629,859	641,819	764,457	2.0
Installed Capability (Summer) – MW	148,668	146,019	158,297	0.9

Peak Demand and Energy

The 1989 through 1999 ten-year annual average compound peak demand growth rate for the Region is projected to be 1.9%. This represents an increase over last year's projected 1.7% growth rate for the 1988-1998 period. The 1989 summer peak demand exceeded forecast by 1.3%.

WSCC's annual energy is projected to grow at an annual average compound rate of 2% from 1989 through 1999. This projected growth in energy requirements is unchanged from that projected for the 1988-1998 period.

Of the four WSCC reporting Areas, the California-Southern Nevada Power Area is projecting the highest ten-year (1989-1999) peak demand growth rate (2.2%), while the Northwest Power Pool Area is projecting the lowest growth rate (0.9%). The highest ten-year annual energy growth within the Region is projected to occur in the Arizona-New Mexico Area (3%). The Northwest Power Pool Area is projecting the lowest ten-year annual energy growth rate within the Region (1.7%).



Generation Adequacy

Generation that is projected to be available during the next ten years is sufficient to reliably serve the anticipated growth in peak demand and annual energy requirements in all areas of the Region.

Net generation additions totalling approximately 14,300 MW are planned through the next ten years. In contrast, net generation additions totalling nearly 32,800 MW, more than twice the amount currently planned, were placed in service during the last ten years. This difference has developed primarily because the growth in electricity demand during the late 1970s and early 1980s was well below expectations, creating a generation surplus. The generation expansion plans for the next ten years are consistent with today's lower peak demand and annual energy growth projections.

Non-utility generators (NUGs) represent 29.3% (4,184 MW) of the planned ten-year net generating capability additions. Although NUG additions represent a significant percentage of the total planned resource additions, these resources will account for only 6.4% of the Region's total resources by 1999.

Flexibility is a key element in the overall planning process. This process includes consideration of all viable options with the goal of maintaining reliability while minimizing the commitment to large capital expenditures and associated financial risks. Conservation and load management programs are examples of viable options that are being implemented along with capacity supply options to reliably balance peak demand and generating capacity. As an example, Northwest utilities are focusing on conservation programs such as residential weatherization, water heater wraps, revision of building codes, commercial energy audits, and industrial modernization incentives. The projected effects of conservation measures are reflected in the demand forecasts.

Transmission Adequacy

The WSCC transmission network, as it exists today and as planned during the next ten years, is adequate to accommodate anticipated firm and most economy electricity transfers. Technical studies conducted annually by the Council and its members assess the ability of the network to withstand a wide range of single and multiple contingency disturbances. Results of the studies are evaluated relative to the Council's reliability criteria. Potential problems are identified and appropriate action is taken to maintain reliability.

WSCC member systems are making a concerted effort to maintain an acceptable level of existing and future system reliability while accommodating higher transfer levels. As an example, operating limits are established on a seasonal basis to define the maximum simultaneous transfers into California that can be accommodated and still achieve reliable performance in the event of a system disturbance. During 106 hours of 1989, electricity transfers into California were curtailed below desired transfer levels to maintain reliability and avoid exceeding simultaneous transfer limits.

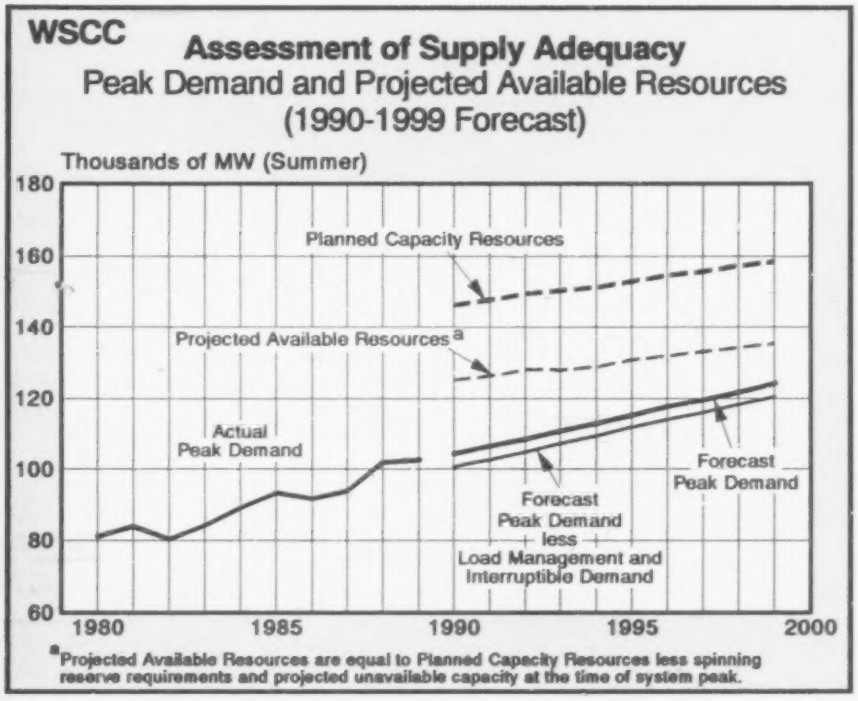
Parallel path flow (loop flow) has contributed to heavy transmission loadings in a number of locations throughout the WSCC Region for years. To significantly mitigate the Region's parallel path flow problems, phase-shifting transformers were installed in the western Colorado-New Mexico transmission system during 1989 and additional phase-shifting transformers will be installed in the transmission lines emanating to the south from Utah during 1990.

Regional Reliability Issues

The following are important issues which must be responsibly managed to avoid degradation of system reliability within the WSCC Region:

- Electric and Magnetic Fields (EMF) — A major transmission line siting issue faced by utilities is the concern regarding potential health hazards associated with exposure to EMF. Electric system reliability could be adversely affected if transmission lines cannot be installed as needed. Research is continuing in an effort to determine whether or not EMF is a health hazard.

- Fuel Supply — Increasing reliance upon natural gas as a primary fuel for generating electricity poses a potential reliability risk. Presently, natural gas is an attractive source of fuel due to its clean burning characteristics and economic advantages. Natural gas supply disruptions and significant increases in gas prices could result in future elec-



tricity supply problems if too much reliance is placed on this fuel source.

- Forecast Uncertainty — Peak demand and annual energy growth projections are based upon a number of variables that can change unpredictably. Variations in weather patterns and economic growth are two factors that have a significant impact on electricity requirements. Utilities are developing and implementing flexible strategies to deal with demand growth uncertainties while maintaining a reasonably priced and reliable electricity supply.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, Utah, portions of Montana, Wyoming, Nevada, and California; and the Canadian provinces of British Columbia and Alberta. Over the period from 1989 through 1999, peak demand and annual energy are projected to grow at respective annual average compound rates of 0.9% and 1.7%. Winter generating capacity margins for this winter peaking area range between 22% and 15% for the next ten years.

Adequate sources of generation are projected to be available to serve the forecast demand growth assuming normal weather patterns, average hydro conditions, and the installation of new generation and transmission facilities as planned. However, since most of the Area's electricity is generated from hydroelectric facilities, there is concern regarding generation adequacy should the area encounter an extended period of below average precipitation or if energy requirements grow at a higher rate than projected. Under adverse hydro conditions, firm energy deficits would be experienced beginning in 1996 and would continue through the end of the ten-year period based upon the current plans for generation additions and demand management programs. The deficits would have to be mitigated by the installation of additional generating facilities, expanded demand management programs, or electricity purchases.

Several major transmission projects are being planned and implemented to maintain reliability and increase electricity transfers with other areas:

- The third 500 kV AC line extending from the Pacific Northwest to California is scheduled for completion in 1992. This new line has a proposed rating that would increase the rating of the three 500 kV AC lines into northern California from 3,200 MW to 4,800 MW. The present Northeast/Southeast islanding scheme which separates the WSCC system into two islands following a simultaneous outage of the two existing AC Pacific Intertie lines is not currently planned for use when all three 500 kV AC Intertie lines are in service.

- Three other projects are in progress to significantly increase transmission transfer capability into the California-Southern Nevada Power Area. A 345 kV line from Utah to southern Nevada is currently under construction and scheduled for completion in 1990. Two 500 kV projects, one consisting of a line from south-central Idaho through eastern Nevada to the Las Vegas area, and the other project consisting of two lines from central Utah to the Las Vegas area, are tentatively planned for completion in 1994/1995.

- Planning is underway to increase the transfer capability of the existing interconnection between the Pacific Northwest and British Columbia. The rating of the interconnection is to be increased from 2,000 MW to 2,300 MW in 1990. Additional 230 kV interconnections between the U.S. Pacific Northwest and British Columbia are being studied. These new interconnections will be located north of both Seattle and Spokane, Washington, and are tentatively scheduled to be placed in service during 1993 and 1995, respectively.

Although the outlook for reliability within the Area over the next ten years is optimistic, there are potential areas of concern:

- Study results indicate the potential for voltage collapse in the Puget Sound area under certain transmission line outage conditions during winter peak demand periods. This condition will become more severe as peak demands continue to increase. Since voltage collapse can result in the uncontrolled loss of customer demand, the utilities

in the Pacific Northwest have implemented operating procedures to address the problem during the near term and have embarked on a major study of the problem to address longer term solutions.

- Simultaneous transfer capability limits, which define the maximum electricity transfers that can occur on the various transmission system interconnections at the same time, are becoming increasingly important to system reliability. Various utilities within the Area are increasing the non-simultaneous capabilities of their individual interconnections as they seek to maximize the benefits of these interconnections. Operation at the higher non-simultaneous limits by a number of utilities at the same time is often not possible due to reliability considerations.

- A major transmission line siting issue faced by utilities is the concern regarding potential health hazards associated with exposure to electromagnetic fields (EMF). Some states within the Northwest have adopted electric field limits, but have not yet adopted magnetic field limits.

Rocky Mountain Power Area

The Rocky Mountain Power Area consists of Colorado, eastern Wyoming, and a small portion of Nebraska and South Dakota. The Area may experience its annual peak demand in either the summer or winter. Over the period from 1989 through 1999, peak demand and annual energy are projected to grow at respective annual average compound rates of 2.1 and 2%. Summer generating capacity margins range between 23% and 28% for the next ten years.

Generating capacity within the Area is surplus to the Area's near term peak demand requirements. During the 1990 through 1994 period, approximately 850 MW to 1,350 MW of surplus generating capacity is available for Area demand growth above that forecast and for export to other Areas. The export of surplus electricity is limited by the transmission capacity to outside Areas. However, transmission system enhancements planned during the early 1990s will provide additional export capability. The availability of surplus generating capacity will be affected by both long-term export commitments to other Areas and the amount of NUG capacity that is actually constructed and placed in service.

Only 2.8% of the Area's firm peak demand is forecast to be served by NUGs during 1990. However, by 1999 the percentage is projected to increase to 11.2%. New tariff provisions for NUG qualifying facilities have been implemented in Colorado, which are expected to result in improved NUG availability and dispatchability. Due to a number of uncertainties, such as the financial viability of the NUG's primary business and the potential for substantial escalation in fuel costs, the amount of NUGs that will actually be financed and constructed is difficult to predict.

Several additions and changes to the Area's transmission system are planned to maintain reliability and enhance the ability to export electricity to outside areas:

- A 345 kV line from Colorado to Utah is scheduled for service during the first quarter of 1990 to bolster the underlying 138 kV system and enable increased electricity transfers to the west.

- A 230 kV line from central to southwest Wyoming is planned for service during 1990 to meet the need for increased transfer capability across the state.

- Transmission additions and reinforcements are underway over the next 2-3 years within Colorado to relieve the heavy loading on the transmission system northeast of Denver.

The outlook for reliability within the Area over the next ten years is favorable. However, the following potential problem areas are a source of concern:

- Continued reliance on special protection systems (remedial action schemes) within the Region for the purpose of operating the transmission system at higher loading levels exposes the electric system to potentially severe consequences if the schemes fail to operate as intended.

- Environmental considerations associated with the EMF issue could adversely affect the construction of new transmission lines, and restrictions on water releases at hydroelectric dam sites could reduce flexibility in the operation of hydroelectric generators.

Arizona-New Mexico Power Area

The Arizona-New Mexico Power Area consists of Arizona, most of New Mexico, and the western-most part of Texas. Over the period from 1989 through 1999, peak demand and annual energy are projected to grow at respective annual compound rates of 2 and 3%. Summer generating capacity margins for this summer peaking area range between 28% and 17% for the next ten years.

The Area has experienced significant differences in actual versus projected peak demands, emphasizing the effects of forecast uncertainty. These differences are attributed to a combination of abnormal weather patterns and primarily downward swings in local economies. The emergence of customers who aggressively pursue electricity purchases from non-traditional suppliers is another factor affecting forecast uncertainty. The net effects have led to the Area's surplus generating capacity.

During the 1990 through 1994 period approximately 1,200 MW to 2,450 MW of surplus generating capacity is available for demand growth above that forecast and for export to other Areas. Increased emphasis is being placed on marketing this capacity to utilities in outside areas. Cold shutdown of some of the Area's gas-, oil-, and coal-fired generating units during autumn months is forecast to continue for several years. Area utilities are coordinating these generating unit shutdown programs to insure that inadvertent capacity shortages are not created during off-peak seasons.

Many of the Area's utilities are forecasting a significant portion of their future demand requirements to be offset by demand management programs. Concern regarding the amount of demand that can be managed is not as prevalent as in the past, due principally to the development of planning philosophies calling for small, short lead-time, resource additions. Maintenance programs are being used to postpone unit retirements and the need for new generating

capacity has been reduced considerably. Relatively few NUGs are forecast within the Area due to low avoided costs and the generally unfavorable match between the primary industries in the Area and those generally associated with NUG cogeneration.

The Arizona to California transmission system has been strengthened through the years. With the addition of phase-shifting transformers across the eastern portion of the WSCC transmission grid, the Four Corners transmission system to the west should experience some relief from its historically high loading levels. Although relief is expected, economic pressure to maintain high transfer levels will continue. The Arizona-New Mexico utilities are continuing to actively work with California and Pacific Northwest utilities, both directly and through WSCC, to increase the assurance that the present and proposed special protection systems will operate reliably and not inadvertently degrade system performance.

Planning is underway to increase the transfer capability between Arizona and Nevada by approximately 1,300 MW with the addition of a Phoenix to Mead/McCullough 500 kV line. The line is presently planned for operation by the spring of 1994.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area encompasses most of California, southern Nevada, and the northern portion of Baja California, Mexico. Over the period from 1989 through 1999, peak demand and annual energy are projected to grow at respective annual compound rates of 2.2 and 2%. Summer generating capacity margins for this summer peaking area range between 26% and 18% for the next ten years.

NUGs account for 9.9% of the Area's existing installed generating capacity and 33.2% of the Area's net generating capacity additions over the next ten years. By 1999 NUGs are projected to comprise 12.9% of the Area's total generating capacity. Nearly all of the NUGs are located within the service territory boundaries of Pacific Gas and Electric Company and Southern California Edison Company. The availability of existing NUGs, especially cogeneration facilities with capacity factors in the 80 to 95% range, has demonstrated that most of these generating units are dependable. In some cases, NUGs have contracted to sell their output to utilities other than the local host utility where they are located. In such cases, issues dealing with transmission service, unit dispatch, and plant control must be resolved among the host utility, NUG, and the utility that is purchasing from the NUG.

Conservation and load management programs will continue to defer the need for new generating plants during the next ten years. Increased commitments to these programs have been made by a number of the utilities in the Area. It is expected that during the 1990-1999 time period these commitments will result in the deferral of 300 MW of new generating capacity in California and southern Nevada.

The California-Southern Nevada Area's transmission system is being strengthened to maintain reliability and accommodate increased electricity transfers with other Areas. Many of the transmission system enhancements have already been described under the headings of the other WSCC reporting Areas. Additional transmission system enhancements include the following:

- A third 500 kV line extending from the Palo Verde nuclear plant in southwestern Arizona to southern California in 1993. This line will significantly strengthen the Arizona to California transmission system.

- An additional 500 kV line from the Las Vegas area to the Los Angeles area in 1994. This line will strengthen the Nevada to California transmission system in conjunction with the transmission projects previously noted in eastern Nevada and western Utah.

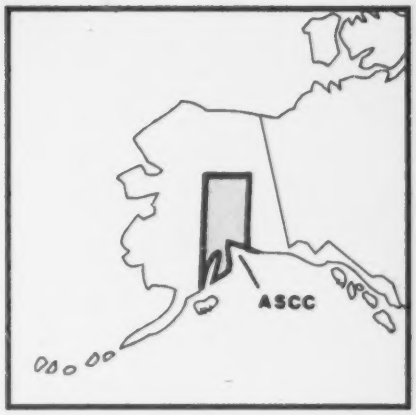
Complex operating procedures (nomograms) and special protection systems are being widely used as a means of economically managing system reliability. Together, they have made possible increased utilization of the transmission system by maximizing simultaneous electricity transfers among several Areas. Since overall reliability of the electric system is critically dependent upon these operating procedures and special protection systems, they must be highly dependable and well coordinated. Their continued use is planned for the future.

Although Area utilities are forecasting an adequate level of reliability over the next ten years, they share the concerns that have been expressed previously regarding those factors that can have a negative affect upon reliability.

An additional emerging concern within the California-Southern Nevada area pertains to non-utility transmission. Non-utility transmission is becoming more commonplace in delivering the output of non-utility generation to a host utility. To date, most of these lines are connected radially from the generator to the network posing no particular problem from a transmission reliability perspective. However, if the lines are integrated into the network and are no longer radial, potential reliability problems can arise if the lines are not designed and operated in compliance with reliability criteria. Close coordination, joint planning, and operating arrangements are required to assure that all transmission, both utility and non-utility, complies with established reliability criteria and will not cause adverse safety and reliability effects on overall system operation.

Western Systems Coordinating Council (WSCC), with 61 member systems and three affiliates, encompasses approximately 1.8 million square miles of territory in 14 western states, two Canadian provinces, and the northern portion of Baja California, Mexico. The Region is characterized by extremes in population and load densities in addition to long distances between load centers and electric generation sources. The Region is subdivided into four areas, namely: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation; the Rocky Mountain Power Area, which is either summer or winter peaking with a 25% hydroelectric and 63% coal-fired generating capacity mix; the Arizona-New Mexico Power Area, which is summer peaking with a 19% nuclear and 44% coal-fired generating capacity mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas- and oil-fired generating units.

ASCC — Alaska Systems Coordinating Council



This assessment addresses only the interconnected electric systems of the Alaska Systems Coordinating Council serving the Anchorage Bowl, the Fairbanks area, and the Kenai Peninsula. These systems are commonly known as the Alaska Railbelt electric utility systems.

The Alaska Railbelt electric utility systems began interconnected operations in 1984 by interconnecting the Fairbanks area with the Anchorage Bowl. (The Anchorage Bowl had been previously interconnected with the Kenai Peninsula in the 1960s.) Assessment of the 1990-1999 generation adequacy clearly indicates that sufficient generating capacity margins exist in each of the three major customer demand areas: the Fairbanks area, the Anchorage Bowl, and the Kenai Peninsula. Neither forced outages nor maintenance outages of generator units are expected to adversely impact generating capacity adequacy.

The two existing Railbelt area interconnection lines are single, limited capacity lines prone to outage by weather and avalanche. These lines constrain the sharing of generation between and among the three customer demand centers and pose a significantly higher than traditional reliability risk for system-wide blackouts due to single contingency outages.

Actual		Forecast		
Summer	1989	1990	1999	Growth Rate
Winter	1989/90	1990/91	1999/00	(%/year)
Summer Peak – MW	455	455	501	1.1
Winter Peak – MW	626	640	697	1.0
Annual Energy – GWh	3,365	3,429	3,778	1.1
Installed Capability (Winter) – MW	1,169	1,149	1,220	0.7

Peak Demand and Energy

Peak demand for the Alaska Railbelt electric utilities occurs in the winter. The 1989/90 winter peak demand was 626 MW. The projected peak for 1990/91 winter is 640 MW. The winter peak demand forecast indicates an average annual growth rate of 1% for the 1990-1999 period.

Annual electrical energy requirements to be supplied by the Alaska Railbelt electric utilities are expected to increase at approximately 1% over the forecast period. The railbelt economy is influenced by events occurring in the oil industry, and continues to be dependent on changes in oil prices and production levels.

Capacity Resources Adequacy

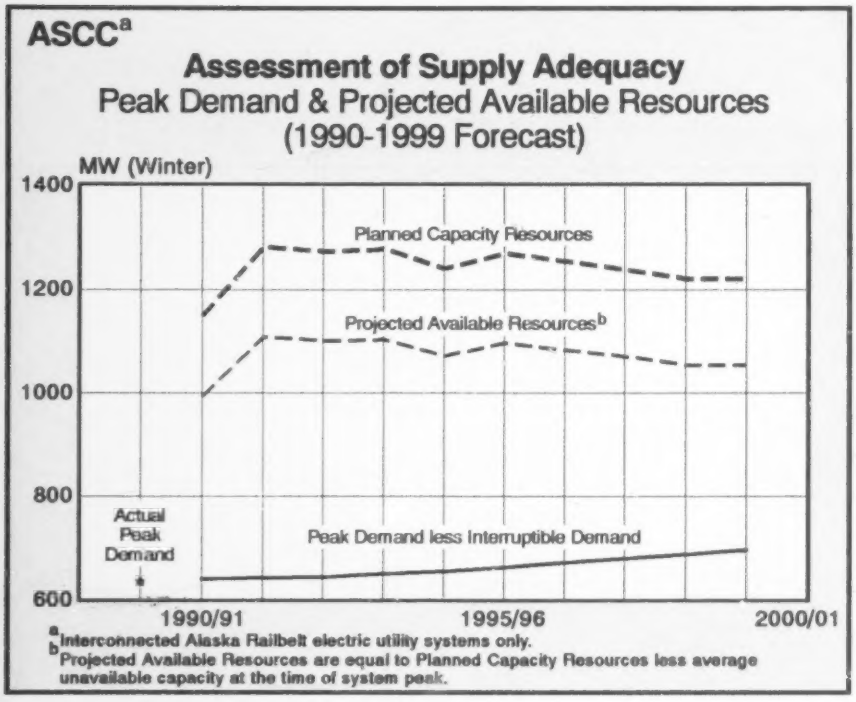
Generating capacity in the Alaska Railbelt electric utilities is approximately 74% natural gas, 18% oil, 4% hydro, and 4% coal. During the ten-year assessment period, the Bradley Lake hydro project (108 MW) will come into service and several smaller natural gas generating units will be removed from service. By the end of the assessment period, the capacity mix will be 66% natural gas, 17% oil, 13% hydro, and 4% coal.

The Intertie Operating Agreement sets forth the criterion for capacity reserve margin that is currently being used by the interconnected Railbelt utilities. This agreement calls for a 30% reserve margin. Assessment of the 1990-1999 generation adequacy indicates that sufficient generating capacity margins exist in each of the three major customer demand areas: Fairbanks, Anchorage, and Kenai.

Transmission Adequacy

As the peak demands and generating capacity of the Alaska Railbelt electric systems are generally in three geographically separate areas, each of the areas has developed its own transmission voltages (115 kV, 138 kV, and 230 kV) that are interconnected by transformation at five substations.

The existing 115 kV interconnection between the Kenai Peninsula and the Anchorage Bowl has a poor reliability history and has a transmission transfer capacity limit under 75 MW. A second line between Anchorage and the Kenai



Peninsula is currently being proposed to improve reliability by preventing the loss of electric service to customers if the existing interconnection line trips (with the exception of those times when the Kenai Peninsula combustion turbines are operating in anticipation of loss of the existing tie).

When Bradley Lake hydro comes into service, reliability will suffer without a second interconnection line between the Kenai Peninsula and the Anchorage Bowl. The proposed second interconnection line is necessary to support Bradley Lake and to help reliably distribute the Bradley Lake capacity to the purchasing systems, to minimize blackouts in the Kenai Peninsula, and to minimize underfrequency customer load shedding in the Fairbanks area and the Anchorage Bowl.

Under traditional reliability criteria, a second transmission line between the Anchorage Bowl and the Fairbanks area would likely be required. A second 138 kV line for a portion of this distance is being proposed from Healy to Fairbanks. This additional line would provide a second path between the Healy coal-fired generating plant and the major part of customer demand in the Fairbanks area.

These two proposed transmission lines are subject to funding by the Alaska State Legislature. To date, funding has not been approved. If these lines are not constructed, the Alaska Railbelt electric utilities will not be able to achieve the level of reliability set forth under NERC guidelines.

Operations

Each Alaska Railbelt electric utility will bring into service additional generating units in anticipation of adverse weather conditions. These generating capacity reserves are geographically located such that they would not be restricted by transmission contingencies. This type of operational response enhances reliability and is encouraged.

At the present time, underfrequency customer load shedding studies are being performed. After these studies are complete, appropriate criteria will be developed and implemented so that a coordinated effort can be made within the Railbelt systems.

Reliability Issues

The major reliability issue in the Alaska Railbelt area concerns transmission adequacy. Electric system reliability is at risk because of a weak transmission link in the overall electrical energy chain of generation, transmission, and distribution facilities.

The current balance between economics and reliability is tailored to the unique geographic, electrical, and economic circumstances facing the Railbelt systems. The cost of providing electric system reliability is exceptionally high due to large distances separating the major customer demand centers. In the past, customers have chosen less reliability in favor of economic benefits. However, there are indications that this balance is shifting toward greater reliability, and the Alaska Railbelt electric utilities are faced with some tough decisions in this area.

The Alaska Systems Coordinating Council (ASCC) is composed of eighteen utilities, a state agency, and a federal agency. Nine ASCC members are interconnected in the Railbelt region of the state. These nine ASCC members account for 75% of the utility net generation for the state of Alaska.

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North American Electric Reliability Council

ECAR
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ERCOT
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MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers).

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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